TITLE 16 ECONOMIC REGULATION

PART 1 RAILROAD COMMISSION OF TEXAS

CHAPTER 3 OIL AND GAS DIVISION

§3.1 Organization Report; Retention of Records; Notice Requirements

(a) Filing requirements.

(1) Except as provided under subsection (e) of this section, no organization, including any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission shall perform such operations without having on file with the Commission an approved organization report and financial security as required by Texas Natural Resources Code §§91.103 - 91.1091. Operations within the jurisdiction of the Commission include, but are not limited to, the following:

(A) drilling, operating, or producing any oil, gas, geothermal resource, brine mining injection, fluid injection, or oil and gas waste disposal well;

(B) transporting, reclaiming, treating, processing, or refining crude oil, gas and products, or geothermal resources and associated minerals;

(C) discharging, storing, handling, transporting, reclaiming, or disposing of oil and gas waste, including hauling salt water for hire by any method other than pipeline;

(D) operating gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance or repressurizing plants, or recycling plants;

(E) recovering skim oil from a salt water disposal site;

(F) nominating crude oil;

(G) operating a directional survey company;

(H) cleaning a reserve pit;

(I) operating a pipeline;

(J) operating as a cementer approved for plugging wells, operating as a cementer cementing casing strings or liners, or operating a well service company performing well stimulation activities, including hydraulic fracturing; or

(K) operating an underground hydrocarbon or natural gas storage facility.

(2) The Commission shall notify organizations that perform operations not included in paragraph (1)(A) - (K) of this subsection of any additional activities subject to the jurisdiction of the Commission which require the filing of the organization report. Such notification shall make the provisions of this section applicable to such activities.

(3) Each organization performing activities subject to the jurisdiction of the Commission shall maintain a current organization report with the Commission until all duties, obligations, and liabilities incurred pursuant to Commission rules, the Natural Resources Code, Titles 3 (Subtitles A, B, C, and Chapter 111 of Subtitle D) and 5, Texas Health and Safety Code, Chapter 401; Texas Utilities Code, §121.201, and the Water Code, Chapters 26, 27, and 29, are fulfilled.

(4) The organization report shall contain the following information:

(A) the name, street address, mailing address, telephone number, and emergency after-hours telephone number of the organization;

(B) the plan of the business organization;

(C) for each officer, director, general partner, owner of more than 25% ownership interest, or trustee (hereinafter controlling entity) of the organization:

(i) that entity's or individual's full legal name, the name(s) under which such entity or individual conducts business in the State of Texas, and all assumed names;

(ii) the following:

(I) if the entity is an individual, his or her social security number. Any individual who does not have a valid social security number shall submit, at that person's option, either his or her valid driver's license or Texas State Identification number;

(II) if the entity is not an individual, the name and, at that person's option, either the valid driver's license, social security, or Texas Identification number of each officer, director, or other person, who, under Texas Natural Resources Code, §91.114, holds a position of ownership or control of the organization, or an active P-5 number for that entity. All controlling entities connected to an organization which are not individuals shall provide the identification of the individuals in ownership or control of those entities.

(iii) a street address different than that of the organization; and

(iv) if different from the mailing address of the organization, a mailing address;

(D) if a foreign or nonresident organization, the name and street address of a resident agent.

As in effect on 12/20/2021.

(E) the name of any non-employee agent that the organization authorizes to act for the organization in signing Oil and Gas Division certificates of compliance which initially designate the operator or change the designation of the operator. Organizations may designate non-employee agents to execute subsequent organization reports. That designation shall be authorized by the organization and not by a non-employee agent.

(5) Any organization may designate a resident agent with a street address different than that of the organization in place of submitting the street addresses of the three (if applicable) primary controlling entities of the organization. Any foreign or nonresident organization identified in paragraph (1) of this subsection shall designate and maintain a resident agent upon whom may be served any process, notice, or demand required or permitted by law to be served upon such entity by or on behalf of the Commission. Failure of such organization to designate and maintain a resident agent shall render the organization report invalid. (Reference Order Number 20-60,617, effective January 1, 1971.)

(6) Failure by any organization identified in paragraph (1) of this subsection to answer any subpoena, commission to take deposition, or directive to appear at a hearing served upon such organization by or on behalf of the Commission shall render the organization report invalid.

(7) An organization shall refile an organization report annually according to the schedule assigned by the Commission. Prior to the filing date, the Commission shall mail notification and information to each organization for update of the organization report file. An organization shall file an amended organization report within 15 days after a change in any information required to be reported in the organization report. Only address changes may be made by letter.

(8) The Commission shall meet any requirement under statute or Commission rule for an order to be sent or notice to be given by the Commission to an organization by mailing the item to the organization's mailing address shown on the most recently filed organization report or the most recently filed letter notification of change of address. Notices sent by regular first-class mail shall be presumed to have been received if, upon arrival of the deadline for any response to the notice, the wrapper containing the notice has not been returned to the Commission. Any Commission action or proceeding for which notice is required shall go forward on the basis of the notice provided under this subsection, whether or not actual notice has been received. Service of notices and orders sent by certified mail is effective upon:

(A) acceptance of the item by any person at the address;

(B) initial failure to claim or refusal to accept the item by any person at the address prior to its eventual return to the Commission by the United States Postal Service; or

(C) return of the item to the Commission by the United States Postal Service bearing a notation such as "addressee unknown," "no forwarding address," "forwarding order expired," or any similar notation indicating that the organization's mailing address shown on the most recently filed organization report or address change notification letter is incorrect.

(9) An organization may also designate to the Commission in writing a specified address for all Commission correspondence relating to a particular district. If designated by an operator, this specified address shall be used in lieu of the organization address for any notices, other than hearing notices, pertaining to that district.

(10) The Commission may return, unapproved, to the organization address an organization report which is submitted to the Commission not fully completed according to the report's written instructions and not timely corrected. In the event that the Commission returns an organization report, all submitted financial assurances shall remain non-refundable. If an organization report approved by the Commission is found to contain information that was materially false at the time it was submitted for approval, the Commission may suspend or revoke the organization report after notice and opportunity for hearing.

(b) Record requirements. All entities who perform operations which are within the jurisdiction of the Commission shall keep books showing accurate records of the drilling, redrilling, or deepening of wells, the volumes of crude oil on hand at the end of each month, the volumes of oil, gas, and geothermal resources produced and disposed of, together with records of such information on leases or property sold or transferred, and other information as required by Commission rules and regulations in connection with the performance of such operations, which books shall be kept open for the inspection of the Commission or its representatives, and shall report such information as required by the Commission to do so.

(c) Time frame. All organizations shall keep copies of records, forms, and documents which are required to be filed with the Commission, along with the supporting documents referred to in subsection (b) of this section, for a period of three years, or longer if required by another Commission rule, and any such copies may be disposed of at the discretion of such entities after the original records, forms, and documents have been on file with the Commission for the required period, except that particular documents shall be retained beyond the required period and until the resolution of pending Commission regulatory enforcement proceedings if the documents contain information material to the determination of any issues therein. All records, forms, and documents required to be filed with the Commission shall be filed in the same name, exactly as it appears on the organization report.

(d) Organization reports for operators of inactive wells.

(1) The Commission or its delegate may approve the

organization report for an operator of an inactive well if the Commission or its delegate has approved an extension of the deadline for plugging the inactive well.

(2) The Commission or its delegate may conditionally approve an organization report if:

(A) the operator assumed responsibility for a well that was inactive at the time of the approval of the operator designation form for the well; and

(B) the Commission or its delegate approved the operator designation form for the inactive well less than six months prior to the date the operator is required to renew its organization report.

(3) The Commission or its delegate may revoke conditional approval of an organization report granted under paragraph (2) of this subsection after notice of opportunity for hearing if the operator has failed to meet any of the following requirements within six months after approval of the operator designation form:

(A) restoration of the well to active status as defined by Commission rule;

(B) plugging of the well in compliance with a Commission rule or order; or

(C) obtaining the approval of the Commission or its delegate of an extension of the deadline for plugging an inactive well.

(e) Issuance of permits to organizations without active organization reports.

(1) Notwithstanding contrary provisions of this section, the Commission or its delegate may issue a permit to an organization or individual that does not have an active organization report or does not ordinarily conduct oil and gas activities when the issuance of such a permit is determined to be necessary to implement a compliance schedule, or to remedy circumstances or a violation of a Commission rule, order, license, permit, or certificate of compliance relating to safety or the prevention of pollution. For permits issued under this subsection, the Commission or its delegate may impose special conditions or terms not found in like permits issued pursuant to other Commission rules. Any organization or individual who requests such a permit shall file an organization report and any other required forms for record-keeping purposes only. The report or form shall contain all information ordinarily required to be submitted to the Commission or its delegate.

(2) This section shall not limit the Commission's authority to plug or to replug wells or to clean up pollution or unpermitted discharges of oil and gas waste.

(f) Each organization required to file an organization report under subsection (a) of this section or an affiliate of such an organization that performs operations within the jurisdiction of the Commission that files for federal bankruptcy protection shall provide written notice to the Commission of that action not later than the 30th day after the date the organization or the affiliate files for bankruptcy protection by submitting the notice to the Enforcement Section of the Office of General Counsel. All bankruptcy-related notices sent to the Commission shall be submitted in writing to that section. For the purpose of this section, affiliate means an organization that is effectively controlled by another.

(g) Neither the Commission nor its delegate may approve an organization report unless the organization has complied with the state registration requirements of the Secretary of State. A tax dispute with the Comptroller of Public Accounts shall not be a basis for disapproving an organization report.

(h) Pursuant to Texas Natural Resources Code, §91.706(b), if an operator uses or reports use of a well for production, injection, or disposal for which the operator's certificate of compliance has been canceled, the Commission or its delegate may refuse to renew the operator's organization report required by Texas Natural Resources Code, §91.142, until the operator pays the fee required by §3.78(b)(9) of this title (relating to Fees and Financial Security Requirements) and the Commission or its delegate issues the certificate of compliance required for that well.

Source Note: The provisions of this §3.1 adopted to be effective January 1, 1976; amended to be effective January 1, 1981, 5 TexReg 4990; amended to be effective February 22, 1986, 11 TexReg 701; amended to be effective December 7, 1987, 12 TexReg 4411; amended to be effective July 22, 1991, 16 TexReg 3767; amended to be effective July 1, 1992, 17 TexReg 4173; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective January 11, 2004, 29 TexReg 359; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective August 27, 2012, 37 TexReg 6538.

§3.2 Commission Access to Properties

(a) The commission or its representatives shall have access to come upon any lease or property operated or controlled by an operator, producer, or transporter of oil, gas, or geothermal resources, and to inspect any and all leases, properties, and wells and all records of said leases, properties, and wells.

(b) Designated agents of the commission are authorized to make any tests on any well at any time necessary for conservation regulation, and the owner of such well is hereby directed to do all things that may be required of him by the commission's agent to make such tests in a proper manner.

Source Note: The provisions of this §3.2 adopted to be effective January 1, 1976; amended to be effective January 30, 2007, 32 TexReg 287.

distance in feet from the wellbore between and including the first take point and the last take point to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information for the surface location of the well, including the Latitude/Longitude or X/Y coordinates in the NAD 27, NAD 83, or WGS 84 coordinate system;

(G) a labeled scale bar; and

(H) northerly direction.

(4) Requirements for plats as provided for in §3.11, §3.37, §3.38, and §3.86 of this title (relating to Inclination and Directional Surveys Required, Statewide Spacing Rule, Well Densities, and Horizontal Drainhole Wells) may supplement or replace the plat requirements set out above.

Source Note: The provisions of this §3.5 adopted to be effective January 1, 1976; amended to be effective September 1, 1983, 8 TexReg 3184; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective October 30, 1986, 11 TexReg 4214; amended to be effective February 24, 1992, 17 TexReg 1225; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective February 1, 2016, 41 TexReg 785.

§3.6 Application for Multiple Completion

(a) Authority will be granted to multicomplete a well in separate reservoirs that are not in communication without the necessity of notice and hearing on each separate application; provided, that an application for multiple completion on the form prescribed and the required accompanying data, as hereafter listed, is filed with the Engineering unit of the Commission's Permitting and Production Section for its consideration and approval.

(b) If the proposed zones of completion are not presently recognized by the commission as being acceptable for multicompletion approval, all data necessary to substantiate a conclusion by the commission that the proposed zones of completion are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein must be filed with the application.

(c) If the additional data furnished with the application is not considered by the commission to be sufficient to establish the proposed zones of completion as separate zones of production which are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein, or if any party protests such an application, then, if an operator so elects, his application will be set for hearing.

(d) Multiple completion authority for a well will not be granted unless the following required data have been filed with the Engineering unit of the Commission's Permitting and Production Section:

(1) application for multiple completion properly executed and attested;

(2) electrical log or portion of the electric log of the well or a type electric log or a portion of the type electric log showing clearly thereon the subsurface location of the separate reservoirs claimed. Any electric log filed will be considered public information pursuant to §3.16 of this title (relating to Log and Completion Report (Statewide Rule 16);

(3) packer setting report where applicable;

(4) packer leakage test or communication test;

(5) diagrammatic sketch of the mechanical installation;

(6) letters of waiver from offset operators, or evidence that notice of application to multicomplete was given to said operators.

Source Note: The provisions of this §3.6 adopted to be effective January 1, 1976; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.7 Strata To Be Sealed Off

Whenever hydrocarbon or geothermal resource fluids are encountered in any well drilled for oil, gas, or geothermal resources in this state, such fluid shall be confined in its original stratum until it can be produced and utilized without waste. Each such stratum shall be adequately protected from infiltrating waters. Wells may be drilled deeper after encountering a stratum bearing such fluids if such drilling shall be prosecuted with diligence and any such fluids be confined in its stratum and protected as aforesaid upon completion of the well. The commission will require each such stratum to be cased off and protected, if in its discretion it shall be reasonably necessary and proper to do so.

Source Note: The provisions of this §3.7 adopted to be effective January 1, 1976.

§3.8 Water Protection

(a) The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Basic sediment pit--Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. Basic sediment pits were formerly referred to as burn

pits.

(2) Brine pit--Pit used for storage of brine which is used to displace hydrocarbons from an underground hydrocarbon storage facility.

(3) Collecting pit--Pit used for storage of saltwater or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.

(4) Completion/workover pit--Pit used for storage or disposal of spent completion fluids, workover fluids and drilling fluid, silt, debris, water, brine, oil scum, paraffin, or other materials which have been cleaned out of the wellbore of a well being completed or worked over.

(5) Drilling fluid disposal pit--Pit, other than a reserve pit, used for disposal of spent drilling fluid.

(6) Drilling fluid storage pit--Pit used for storage of drilling fluid which is not currently being used but which will be used in future drilling operations. Drilling fluid storage pits are often centrally located among several leases.

(7) Emergency saltwater storage pit--Pit used for storage of produced saltwater for limited period of time. Use of the pit is necessitated by a temporary shutdown of disposal well or fluid injection well and/or associated equipment, by temporary overflow of saltwater storage tanks on a producing lease or by a producing well loading up with formation fluids such that the well may die. Emergency saltwater storage pits may sometimes be referred to as emergency pits or blowdown pits.

(8) Flare pit--Pit which contains a flare and which is used for temporary storage of liquid hydrocarbons which are sent to the flare during equipment malfunction but which are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or a well.

(9) Fresh makeup water pit--Pit used in conjunction with a drilling rig for storage of fresh water used to make up drilling fluid or hydraulic fracturing fluid.

(10) Gas plant evaporation/retention pit--Pit used for storage or disposal of cooling tower blowdown, water condensed from natural gas, and other wastewater generated at gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants.

(11) Mud circulation pit--Pit used in conjunction with drilling rig for storage of drilling fluid currently being used in drilling operations.

(12) Reserve pit--Pit used in conjunction with drilling rig for collecting spent drilling fluids; cuttings, sands, and silts; and wash water used for cleaning drill pipe and other equipment at the well site. Reserve pits are sometimes referred to as slush pits or mud pits.

(13) Saltwater disposal pit--Pit used for disposal of produced saltwater.

(14) Skimming pit--Pit used for skimming oil off saltwater prior to disposal of saltwater at a disposal well or fluid injection well.

(15) Washout pit--Pit located at a truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.

(16) Water condensate pit--Pit used in conjunction with a gas pipeline drip or gas compressor station for storage or disposal of fresh water condensed from natural gas.

(17) Generator--Person who generates oil and gas wastes.

(18) Carrier--Person who transports oil and gas wastes generated by a generator. A carrier of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(19) Receiver--Person who stores, handles, treats, reclaims, or disposes of oil and gas wastes generated by a generator. A receiver of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(20) Director--Director of the Oil and Gas Division or his staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(21) Person--Natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(22) Affected person--Person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(23) To dewater--To remove the free water.

(24) To dispose--To engage in any act of disposal subject to regulation by the commission including, but not limited to, conducting, draining, discharging, emitting, throwing, releasing, depositing, burying, landfarming, or allowing to seep, or to cause or allow any such act of disposal.

(25) Landfarming--A waste management practice in which oil and gas wastes are mixed with or applied to the land surface in such a manner that the waste will not migrate off the landfarmed area.

(26) Oil and gas wastes--Materials to be disposed of or reclaimed which have been generated in connection with

activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in paragraph (30) of this subsection, and materials to be disposed of or reclaimed which have been generated in connection with activities associated with the solution mining of brine. The term "oil and gas wastes" includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil, spent completion fluids, and other liquid, semiliquid, or solid waste material. The term "oil and gas wastes" includes waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants unless that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901 et seq.).

(27) Oil field fluids--Fluids to be used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, fluids to be used or reused in connection with activities associated with the solution mining of brine, and mined brine. The term "oil field fluids" includes, but is not limited to, drilling fluids, completion fluids, surfactants, and chemicals used to detoxify oil and gas wastes.

(28) Pollution of surface or subsurface water--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(29) Surface or subsurface water--Groundwater, percolating or otherwise, and lakes, bays, ponds, impounding reservoirs, springs, rivers, streams, creeks, estuaries, marshes, inlets, canals, the Gulf of Mexico inside the territorial limits of the state, and all other bodies of surface water, natural or artificial, inland or coastal, fresh or salt, navigable or nonnavigable, and including the beds and banks of all watercourses and bodies of surface water, that are wholly or partially inside or bordering the state or inside the jurisdiction of the state.

(30) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil or gas or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil or gas or geothermal resources;

(iii) activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph, except for waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901, et seq.).

(31) Mined brine--Brine produced from a brine mining injection well by solution of subsurface salt formations. The term "mined brine" does not include saltwater produced incidentally to the exploration, development, and production of oil or gas or geothermal resources.

(32) Brine mining pit--Pit, other than a fresh mining water pit, used in connection with activities associated with the solution mining of brine. Most brine mining pits are used to store mined brine.

(33) Fresh mining water pit--Pit used in conjunction with a brine mining injection well for storage of water used for solution mining of brine.

(34) Inert wastes--Nonreactive, nontoxic, and essentially insoluble oil and gas wastes, including, but not limited to, concrete, glass, wood, metal, wire, plastic, fiberglass, and trash.

(35) Coastal zone--The area within the boundary established in Title 31, Texas Administrative Code, §503.1 (Coastal Management Program Boundary).

(36) Coastal management program (CMP) rules--The enforceable rules of the Texas Coastal Management Program codified at Title 31, Texas Administrative Code, Chapters 501, 505, and 506.

(37) Coastal natural resource area (CNRA)--One of the following areas defined in Texas Natural Resources Code, §33.203: coastal barriers, coastal historic areas, coastal preserves, coastal shore areas, coastal wetlands, critical dune areas, critical erosion areas, gulf beaches, hard substrate reefs, oyster reefs, submerged land, special hazard areas, submerged aquatic vegetation, tidal sand or mud flats, water in the open Gulf of Mexico, and water under tidal influence.

(38) Coastal waters--Waters under tidal influence and waters of the open Gulf of Mexico.

(39) Critical area--A coastal wetland, an oyster reef, a hard substrate reef, submerged aquatic vegetation, or a tidal sand or mud flat as defined in Texas Natural Resources Code, §33.203.

(40) Practicable--Available and capable of being done after taking into consideration existing technology, cost, and logistics in light of the overall purpose of the activity.

(41) Non-commercial fluid recycling--The recycling of fluid produced from an oil or gas well, including produced formation fluid, workover fluid, and completion fluid, including fluids produced from the hydraulic fracturing process on an existing commission-designated lease or drilling unit associated with a commission-issued drilling permit or upon land leased or owned by the operator for the purposes of operation of a non-commercial disposal well operated pursuant to a permit issued under §3.9 of this title (relating to Disposal Wells) or a non-commercial injection well operated pursuant to a permit issued under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs), where the operator of the lease, or drilling unit, or non-commercial disposal or injection well treats or contracts with a person for the treatment of the fluid, and may accept such fluid from other leases and or operators.

(42) Non-commercial fluid recycling pit--Pit used in conjunction with one or more oil or gas leases or units that is constructed, maintained, and operated by the operator of record of the lease or unit and is located on an existing commission-designated lease or drilling unit associated with a commission-issued drilling permit, or upon land leased or owned by the operator for the purposes of operation of a non-commercial disposal well operated pursuant to a permit issued under §3.9 of this title or a non-commercial injection well operated pursuant to a permit issued under §3.46 of this title, for the storage of fluid for the purpose of non-commercial fluid recycling or for the storage of treated fluid.

(43) Recycle--To process and/or use or re-use oil and gas wastes as a product for which there is a legitimate commercial use and the actual use of the recyclable product. 'Recycle,' as defined in this subsection, does not include injection pursuant to a permit issued under §3.46 of this title.

(44) Treated fluid-Fluid that has been treated using water treatment technologies to remove impurities such that the treated fluid can be reused or recycled. Treated fluid is not a waste but may become a waste if it is abandoned or disposed of rather than reused or recycled.

(45) Recyclable product--A reusable material as defined in §4.204(12) of this title (relating to Definitions).

(46) 100-year flood plain--An area that is inundated by a 100-year flood, which is a flood that has a one percent or greater chance of occurring in any given year, as determined from maps or other data from the Federal Emergency Management Administration (FEMA), or, if not mapped by FEMA, from the United States Department of Agriculture soil maps.

(47) Distilled water--Water that has been purified by being heated to a vapor form and then condensed into another container as liquid water that is essentially free of all solutes.

(b) No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(c) Exploratory wells. Any oil, gas, or geothermal resource well or well drilled for exploratory purposes shall be governed by the provisions of statewide or field rules which are applicable and pertain to the drilling, safety, casing, production, abandoning, and plugging of wells.

(d) Pollution control.

(1) Prohibited disposal methods. Except for those disposal methods authorized for certain wastes by paragraph (3) of this subsection, subsection (e) of this section, or §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), or disposal methods required to be permitted pursuant to §3.9 of this title (relating to Disposal Wells) (Rule 9) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Rule 46), no person may dispose of any oil and gas wastes by any method without obtaining a permit to dispose of such wastes. The disposal methods prohibited by this paragraph include, but are not limited to, the unpermitted discharge of oil field brines, geothermal resource waters, or other mineralized waters, or drilling fluids into any watercourse or drainageway, including any drainage ditch, dry creek, flowing creek, river, or any other body of surface water.

(2) Prohibited pits. No person may maintain or use any pit for storage of oil or oil products. Except as authorized by this subsection, no person may maintain or use any pit for storage of oil field fluids, or for storage or disposal of

oil and gas wastes, without obtaining a permit to maintain or use the pit. A person is not required to have a permit to use a pit if a receiver has such a permit, if the person complies with the terms of such permit while using the pit, and if the person has permission of the receiver to use the pit. The pits required by this paragraph to be permitted include, but are not limited to, the following types of pits: saltwater disposal pits; emergency saltwater storage pits; collecting pits; skimming pits; brine pits; brine mining pits; drilling fluid storage pits (other than mud circulation pits); drilling fluid disposal pits (other than reserve pits or slush pits); washout pits; and gas plant evaporation/retention pits. If a person maintains or uses a pit for storage of oil field fluids, or for storage or disposal of oil and gas wastes, and the use or maintenance of the pit is neither authorized by this subsection nor permitted, then the person maintaining or using the pit shall backfill and compact the pit in the time and manner required by the director. Prior to backfilling the pit, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by paragraph (3) of this subsection, dispose of all oil and gas wastes which are in the pit.

(3) Authorized disposal methods.

(A) Fresh water condensate. A person may, without a permit, dispose of fresh water which has been condensed from natural gas and collected at gas pipeline drips or gas compressor stations, provided the disposal is by a method other than disposal into surface water of the state.

(B) Inert wastes. A person may, without a permit, dispose of inert and essentially insoluble oil and gas wastes including, but not limited to, concrete, glass, wood, and wire, provided the disposal is by a method other than disposal into surface water of the state.

(C) Low chloride drilling fluid. A person may, without a permit, dispose of the following oil and gas wastes by landfarming, provided the wastes are disposed of on the same lease where they are generated, and provided the person has the written permission of the surface owner of the tract where landfarming will occur: water base drilling fluids with a chloride concentration of 3,000 milligrams per liter (mg/liter) or less; drill cuttings, sands, and silts obtained while using water base drilling fluids with a chloride concentration of 3,000 mg/liter or less; and wash water used for cleaning drill pipe and other equipment at the well site.

(D) Other drilling fluid. A person may, without a permit, dispose of the following oil and gas wastes by burial, provided the wastes are disposed of at the same well site where they are generated: water base drilling fluid which had a chloride concentration in excess of 3,000 mg/liter but which have been dewatered; drill cuttings, sands, and silts obtained while using oil base drilling fluids or water base drilling fluids with a chloride concentration in excess of 3,000 mg/liter; and those drilling fluids and wastes allowed to be landfarmed without a permit.

(E) Completion/workover pit wastes. A person may, without a permit, dispose of the following oil and gas wastes by burial in a completion/workover pit, provided the wastes have been dewatered, and provided the wastes are disposed of at the same well site where they are generated: spent completion fluids, workover fluids, and the materials cleaned out of the wellbore of a well being completed or worked over.

(F) Contents of non-commercial fluid recycling pit. A person may, without a permit, dispose of the solids from a non-commercial fluid recycling pit by burial in the pit, provided the pit has been dewatered.

(G) Effect on backfilling. A person's choice to dispose of a waste by methods authorized by this paragraph shall not extend the time allowed for backfilling any reserve pit, mud circulation pit, or completion/workover pit whose use or maintenance is authorized by paragraph (4) of this subsection.

(4) Authorized pits. A person may, without a permit, maintain or use reserve pits, mud circulation pits, completion/workover pits, basic sediment pits, flare pits, fresh makeup water pits, fresh mining water pits, non-commercial fluid recycling pits, and water condensate pits on the following conditions.

(A) Reserve pits and mud circulation pits. A person shall not deposit or cause to be deposited into a reserve pit or mud circulation pit any oil field fluids or oil and gas wastes, other than the following:

(i) drilling fluids, whether fresh water base, saltwater base, or oil base;

(ii) drill cuttings, sands, and silts separated from the circulating drilling fluids;

(iii) wash water used for cleaning drill pipe and other equipment at the well site;

(iv) drill stem test fluids; and

(v) blowout preventer test fluids.

(B) Completion/workover pits. A person shall not deposit or cause to be deposited into a completion/workover pit any oil field fluids or oil and gas wastes other than spent completion fluids, workover fluid, and the materials cleaned out of the wellbore of a well being completed or worked over.

(C) Basic sediment pits. A person shall not deposit or cause to be deposited into a basic sediment pit any oil field fluids or oil and gas wastes other than basic sediment removed from a production vessel or from the bottom of an oil storage tank. Although a person may store basic sediment in a basic sediment pit, a person may not deposit oil or free saltwater in the pit. The total capacity of a basic sediment pit shall not exceed a capacity of 50 barrels. The area covered by a basic sediment pit shall not exceed 250 square feet.

(D) Flare pits. A person shall not deposit or cause to be deposited into a flare pit any oil field fluids or oil and gas wastes other than the hydrocarbons designed to go to the flare during upset conditions at the well, tank battery, or gas plant where the pit is located. A person shall not store liquid hydrocarbons in a flare pit for more than 48 hours at a time.

(E) Fresh makeup water pits and fresh mining water pits. A person shall not deposit or cause to be deposited into a fresh makeup water pit any oil and gas wastes or any oil field fluids other than fresh water used to make up drilling fluid or hydraulic fracturing fluid. A person shall not deposit or cause to be deposited into a fresh mining water pit any oil and gas wastes or any oil field fluids other than water used for solution mining of brine.

(F) Water condensate pits. A person shall not deposit or cause to be deposited into a water condensate pit any oil field fluids or oil and gas wastes other than fresh water condensed from natural gas and collected at gas pipeline drips or gas compressor stations.

(G) Non-commercial fluid recycling pits.

(i) A person shall not deposit or cause to be deposited into a non-commercial fluid recycling pit any oil field fluids or oil and gas wastes other than those fluids described in subsection (a)(42) of this section.

(ii) All pits shall be sufficiently large to ensure adequate storage capacity and freeboard taking into account anticipated precipitation.

(iii) All pits shall be designed to prevent stormwater runoff from entering the pit. If a pit is constructed with a dike or berm, the height, slope, and construction material of such dike or berm shall be such that it is structurally sound and does not allow seepage.

(iv) A freeboard of at least two feet shall be maintained at all times.

(v) All pits shall be lined. The liner shall be designed, constructed, and installed to prevent any migration of materials from the pit into adjacent subsurface soils, ground water, or surface water at any time during the life of the pit. The liner shall be installed according to standard industry practices, shall be constructed of materials that have sufficient chemical and physical properties, including thickness, to prevent failure during the expected life of the pit. All liners shall have a hydraulic conductivity that is 1.0×10^{-7} cm/sec or less. A liner may be constructed of either natural or synthetic materials.

(I) Procedures shall be in place to routinely monitor the integrity of the liner of pit. If liner failure is discovered at any time, the pit shall be emptied and the liner repaired prior to placing the pit back in service. Acceptable monitoring procedures include an annual visual inspection of the pit liner or the installation of a double liner and leak detection system. Alternative monitoring procedures may be approved by the director if the operator demonstrates that the alternative is at least equivalent in the protection of surface and subsurface water as the provisions of this section.

(II) The liner of a pit with a single liner shall be inspected annually to ensure that the liner has not failed. This inspection shall be completed by emptying the pit and visually inspecting the liner.

(III) If the operator does not propose to empty the pit and inspect the pit liner on at least an annual basis, the operator shall install a double liner and leak detection system. A leak detection system shall be installed between a primary and secondary liner. The leak detection system must be monitored on a monthly basis to determine if the primary liner has failed. The primary liner has failed if the volume of water passing through the primary liner exceeds the action leakage rate, as calculated using accepted procedures, or 1,000 gallons per acre per day, whichever is larger.

(IV) The operator of the pit shall keep records to demonstrate compliance with the pit liner integrity requirements and shall make the records available to commission personnel upon request.

(vi) The operator of the pit shall provide written notification to the district director prior to construction of the pit, or prior to the use of an existing pit as a non-commercial fluid recycling pit. Such notification shall include:

(I) the location of the pit including the lease name and number or drilling permit number and the latitude and longitude;

(II) the dimensions and maximum capacity of the pit; and

(III) a signed statement that the operator has written permission from the surface owner of the tract upon which the pit is located for construction and use of the pit for such purpose.

(vii) Equipment, machinery, waste, or other materials that could reasonably be expected to puncture, tear, or otherwise compromise the integrity of the liner shall not be used or placed in lined pits.

(viii) The pit shall be inspected periodically by the operator for compliance with the applicable provisions of this section.

(H) Backfill requirements.

(i) A person who maintains or uses a reserve pit, mud circulation pit, fresh makeup water pit, fresh mining water pit, completion/workover pit, basic sediment pit, flare pit, non-commercial fluid recycling pit, or water condensate pit shall dewater, backfill, and compact the pit according to the following schedule.

(I) Reserve pits and mud circulation pits which contain fluids with a chloride concentration of 6,100 mg/liter or less and fresh makeup water pits shall be dewatered, backfilled, and compacted within one year of cessation of drilling operations.

(II) Reserve pits and mud circulation pits which contain fluids with a chloride concentration in excess of 6,100 mg/liter shall be dewatered within 30 days and backfilled and compacted within one year of cessation of drilling operations.

(III) All completion/workover pits used when completing a well shall be dewatered within 30 days and backfilled and compacted within 120 days of well completion. All completion/workover pits used when working over a well shall be dewatered within 30 days and backfilled and compacted within 120 days of completion of workover operations.

(IV) Basic sediment pits, flare pits, fresh mining water pits, non-commercial fluid recycling pits, and water condensate pits shall be dewatered, backfilled, and compacted within 120 days of final cessation of use of the pits.

(V) If a person constructs a sectioned reserve pit, each section of the pit shall be considered a separate pit for determining when a particular section should be dewatered.

(ii) A person who maintains or uses a reserve pit, mud circulation pit, fresh makeup water pit, non-commercial fluid recycling pit, or completion/workover pit shall remain responsible for dewatering, backfilling, and compacting the pit within the time prescribed by clause (i) of this subparagraph, even if the time allowed for backfilling the pit extends beyond the expiration date or transfer date of the lease covering the land where the pit is located.

(iii) The director may require that a person who uses or maintains a reserve pit, mud circulation pit, fresh makeup water pit, fresh mining water pit, completion/workover pit, basic sediment pit, flare pit, non-commercial fluid recycling pit, or water condensate pit backfill the pit sooner than the time prescribed by clause (i) of this subparagraph if the director determines that oil and gas wastes or oil field fluids are likely to escape from the pit or that the pit is being used for improper storage or disposal of oil and gas wastes or oil field fluids.

(iv) Prior to backfilling any reserve pit, mud circulation pit, completion/workover pit, basic sediment pit, flare pit, non-commercial fluid recycling pit, or water condensate pit whose use or maintenance is authorized by this paragraph, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by paragraph (3) of this subsection, dispose of all oil and gas wastes which are in the pit.

(I) Unless otherwise approved by the district director after a showing that the fluids will be confined in the pit at all times, all authorized pits shall be constructed, used, operated, and maintained at all times outside of a 100-year flood plain as that term is defined in subsection (a) of this section. The operator may request a hearing if the district director denies approval of the request to construct a pit within a 100-year flood plain.

(II) In the event of an unauthorized discharge from any pit authorized by this paragraph, the operator shall take any measures necessary to stop or control the discharge and report the discharge to the district office as soon as possible.

(5) Responsibility for disposal.

(A) Permit required. No generator or receiver may knowingly utilize the services of a carrier to transport oil and gas wastes if the carrier is required by this rule to have a permit to transport such wastes but does not have such a permit. No carrier may knowingly utilize the services of a second carrier to transport oil and gas wastes if the second carrier is required by this rule to have a permit to transport such wastes but does not have such a permit. No generator or carrier may knowingly utilize the services of a receiver to store, handle, treat, reclaim, or dispose of oil and gas wastes if the receiver is required by statute or commission rule to have a permit to store, handle, treat, reclaim, or dispose of such wastes but does not have such a permit. No receiver may knowingly utilize the services of a second receiver to store, handle, treat, reclaim, or dispose of oil and gas wastes if the second receiver is required by statute or commission rule to have a permit to store, handle, treat, reclaim, or dispose of such wastes but does not have such a permit. Any person who plans to utilize the services of a carrier or receiver is under a duty to determine that the carrier or receiver has all permits required by the Oil and Gas Division to transport, store, handle, treat, reclaim, or dispose of oil and gas wastes.

(B) Improper disposal prohibited. No generator, carrier, receiver, or any other person may improperly dispose of oil and gas wastes or cause or allow the improper disposal of oil and gas wastes. A generator causes or allows the improper disposal of oil and gas wastes if:

(i) the generator utilizes the services of a carrier or receiver who improperly disposes of the wastes; and

(ii) the generator knew or reasonably should have known that the carrier or receiver was likely to improperly dispose of the wastes and failed to take reasonable steps to prevent the improper disposal.

(6) Permits.

(A) Standards for permit issuance. A permit to maintain or use a pit for storage of oil field fluids or oil and gas wastes may only be issued if the commission determines that the maintenance or use of such pit will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface waters. A permit to dispose of oil and gas wastes by any method, including disposal into a pit, may only be issued if the commission determines that the disposal will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water. A permit to maintain or use any unlined brine mining pit or any unlined pit, other than an emergency saltwater storage pit, for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters may only be issued if the commission determines that the applicant has conclusively shown that use of the pit cannot cause pollution of surrounding productive agricultural land nor pollution of surface or subsurface water, either because there is no surface or subsurface water in the area of the pit, or because the surface or subsurface water in the area of the pit would be physically isolated by naturally occurring impervious barriers from any oil and gas wastes which might escape or migrate from the pit. Permits issued pursuant to this paragraph will contain conditions reasonably necessary to prevent the waste of oil, gas, or geothermal resources and the pollution of surface and subsurface waters. A permit to maintain or use a pit will state the conditions under which the pit may be operated, including the conditions under which the permittee shall be required to dewater, backfill, and compact the pit. Any permits issued pursuant to this paragraph may contain requirements concerning the design and construction of pits and disposal facilities, including requirements relating to pit construction materials, dike design, liner material, liner thickness, procedures for installing liners, schedules for inspecting and/or replacing liners, overflow warning devices, leak detection devices, and fences. However, a permit to maintain or use any lined brine mining pit or any lined pit for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters will contain requirements relating to liner material, liner thickness, procedures for installing liners, and schedules for inspecting and/or replacing liners.

(B) Application. An application for a permit to maintain or use a pit or to dispose of oil and gas wastes shall be filed with the commission in Austin. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the original application is mailed or delivered to the commission in Austin. A permit application shall be considered filed with the commission on the date it is received by the commission in Austin. When a commission-prescribed application form exists, an applicant shall make application on the prescribed form according to the instructions on such form. The director may require the applicant to provide the commission with engineering, geological, or other information which the director deems necessary to show that issuance of the permit will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water.

(C) Notice. The applicant shall give notice of the permit application to the surface owners of the tract upon which the pit will be located or upon which the disposal will take place. When the tract upon which the pit will be located or upon which the disposal will take place lies within the corporate limits of an incorporated city, town, or village, the applicant shall also give notice to the city clerk or other appropriate official. Where disposal is to be by discharge into a watercourse other than the Gulf of Mexico or a bay, the applicant shall also give notice to the surface owners of each waterfront tract between the discharge point and 1/2 mile downstream of the discharge point except for those waterfront tracts within the corporate limits of an incorporated city, town, or village. When one or more waterfront tracts within 1/2 mile of the discharge point lie within the corporate limits of an incorporated city, town, or village, the applicant shall give notice to the city clerk or other appropriate official. Notice of the permit application shall consist of a copy of the application together with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission. The applicant shall mail or deliver the required notice to the surface owners and the city clerk or other appropriate official on or before the date the application is mailed or delivered to the commission in Austin. If, in connection with a particular application, the director determines that another class of persons, such as offset operators, adjacent surface owners, or an appropriate river authority, should receive notice of the application, the director may require the applicant to mail or deliver notice to members of that class. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required by this subparagraph to be notified, then the director may authorize the applicant to notify such persons by publishing notice of the application. The director shall determine the form of the notice to be published. The notice shall be published once each week for two consecutive weeks by the applicant in a newspaper of general circulation in the county where the pit will be located or the disposal will take place. The applicant shall file proof of publication with the commission in Austin. The director will consider the applicant to have made diligent efforts to ascertain the names and addresses of surface owners required by this subparagraph to be notified if the applicant has examined the current county tax rolls and investigated other reliable and readily available sources of information.

(D) Protests and hearings. If a protest from an affected person is made to the commission within 15 days of the date the application is filed, then a hearing shall be held on the application after the applicant requests a hearing. If the director has reason to believe that a person entitled to notice of an application has not received such notice within 15 days of the date an application is filed with the commission, then the director shall not take action on the application until reasonable efforts have been made to give such person notice of the application and an opportunity to file a protest to the application. If the director determines that a hearing is in the public interest, a hearing shall be held. A hearing on an application shall be held after the commission provides notice of hearing to all affected persons, or other persons or governmental entities who express an interest in the application in writing. If no protest from an affected person is received by the commission, the director may administratively approve the application. If the director denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the hearings examiner shall recommend a final action by the commission.

(E) Modification, suspension, and termination. A permit granted pursuant to this subsection, may be modified, suspended, or terminated by the commission for good cause after notice and opportunity for hearing. A finding of any of the following facts shall constitute good cause:

(i) pollution of surface or subsurface water is occurring or is likely to occur as a result of the permitted operations;

(ii) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations;

(iii) the permittee has violated the terms and conditions of the permit or commission rules;

(iv) the permittee misrepresented any material fact during the permit issuance process;

(v) the permittee failed to give the notice required by the commission during the permit issuance process;

(vi) a material change of conditions has occurred in the permitted operations, or the information provided in the application has changed materially.

(F) Emergency permits. If the director determines that expeditious issuance of the permit will prevent or is likely to prevent the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water, the director may issue an emergency permit. An application for an emergency permit to use or maintain a pit or to dispose of oil and gas wastes shall be filed with the commission in the appropriate district office. Notice of the application is not required. If warranted by the nature of the emergency, the director may issue an emergency permit based upon a verbal application, or the director may verbally authorize an activity before issuing a written permit authorizing that activity. An emergency permit is valid for up to 30 days, but may be modified, suspended, or terminated by the director at any time for good cause without notice and opportunity for hearing. Except when the provisions of this subparagraph are to the contrary, the issuance, denial, modification, suspension, or termination of an emergency permit shall be governed by the provisions of subparagraphs (A) - (E) of this paragraph.

(G) Minor permits. If the director determines that an application is for a permit to store only a minor amount of oil field fluids or to store or dispose of only a minor amount of oil and gas waste, the director may issue a minor permit provided the permit does not authorize an activity which results in waste of oil, gas, or geothermal resources or pollution of surface or subsurface water. An application for a minor permit shall be filed with the commission in the appropriate district office. Notice of the application shall be given as required by the director. The director may determine that notice of the application is not required. A minor permit is valid for 60 days, but a minor permit which is issued without notice of the application may be modified, suspended, or terminated by the director at any time for good cause without notice and opportunity for hearing. Except when the provisions of this subparagraph are to the contrary, the issuance, denial, modification, suspension, or termination of a minor permit shall be governed by the provisions of subparagraphs (A) - (E) of this paragraph.

(7) Recycling.

(A) Prohibited recycling. Except for those recycling methods authorized for certain wastes by subparagraph (B) of this paragraph, no person may recycle any oil and gas wastes by any method without obtaining a permit.

(B) Authorized recycling.

(i) No permit is required if treated fluid is recycled for use as makeup water for a hydraulic fracturing fluid treatment(s), or as another type of oilfield fluid to be used in the wellbore of an oil, gas, geothermal, or service well.

(ii) Treated fluid may be reused in any other manner, other than discharge to waters of the state, without a permit from the Commission, provided the reuse occurs pursuant to a permit issued by another state or federal agency.

(iii) If treatment of the fluid results in distilled water, no permit is required to use the resulting distilled water in any manner other than discharge to waters of the state.

(iv) Fluid that meets the requirements of clause (i), (ii), or (iii) of this subparagraph is a recyclable product.

(C) Permitted recycling.

(i) Treated fluid may be reused in any manner, other than the manner authorized by subparagraph (B) of this paragraph, pursuant to a permit issued by the director on a case-by-case basis, taking into account the source of the fluids, the anticipated constituents of concern, the volume of fluids, the location, and the proposed reuse of the treated fluids. Fluid that meets the requirements of a permit issued under this clause is a recyclable product.

(ii) All commercial recycling requires the commercial recycler of the oil and gas waste to obtain a permit in accordance with Chapter 4, Subchapter B of this title (relating to Commercial Recycling).

(8) Used oil. Used oil as defined in §3.98 of this title, shall be managed in accordance with the provisions of 40 CFR, Part 279.

(e) Pollution prevention (reference Order Number 20-59,200, effective May 1, 1969).

(1) The operator shall not pollute the waters of the Texas offshore and adjacent estuarine zones (saltwater

bearing bays, inlets, and estuaries) or damage the aquatic life therein.

(2) All oil, gas, and geothermal resource well drilling and producing operations shall be conducted in such a manner to preclude the pollution of the waters of the Texas offshore and adjacent estuarine zones. Particularly, the following procedures shall be utilized to prevent pollution.

(A) The disposal of liquid waste material into the Texas offshore and adjacent estuarine zones shall be limited to saltwater and other materials which have been treated, when necessary, for the removal of constituents which may be harmful to aquatic life or injurious to life or property.

(B) No oil or other hydrocarbons in any form or combination with other materials or constituent shall be disposed of into the Texas offshore and adjacent estuarine zones.

(C) All deck areas on drilling platforms, barges, workover unit, and associated equipment both floating and stationary subject to contamination shall be either curbed and connected by drain to a collecting tank, sump, or enclosed drilling slot in which the containment will be treated and disposed of without causing hazard or pollution; or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans must be piped to collecting tanks, sumps, or enclosed drilling slots to prevent overflow or prevent pollution of the surrounding water.

(D) Solid combustible waste may be burned and the ashes may be disposed of into Texas offshore and adjacent estuarine zones. Solid wastes such as cans, bottles, or any form of trash must be transported to shore in appropriate containers. Edible garbage, which may be consumed by aquatic life without harm, may be disposed of into Texas offshore and adjacent estuarine zones.

(E) Drilling muds which contain oil shall be transported to shore or a designated area for disposal. Only oil-free cutting and fluids from mud systems may be disposed of into Texas offshore and adjacent estuarine zones at or near the surface.

(F) Fluids produced from offshore wells shall be mechanically contained in adequately pressure-controlled piping or vessels from producing well to disposition point. Oil and water separation facilities at offshore and onshore locations shall contain safeguards to prevent emission of pollutants to the Texas offshore and adjacent estuarine zones prior to proper treatment.

(G) All deck areas on producing platforms subject to contamination shall be either curbed and connected by drain to a collecting tank or sump in which the containment will be treated and disposed of without causing hazard or pollution, or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans must be piped to collecting tanks or sumps designed to accommodate all reasonably expected drainage. Satisfactory means must be provided to empty the sumps to prevent overflow.

(H) Any person observing water pollution shall report such sighting, noting size, material, location, and current conditions to the ranking operating personnel. Immediate action or notification shall be made to eliminate further pollution. The operator shall then transmit the report to the appropriate commission district office.

(I) Immediate corrective action shall be taken in all cases where pollution has occurred. An operator responsible for the pollution shall remove immediately such oil, oil field waste, or other pollution materials from the waters and the shoreline where it is found. Such removal operations will be at the expense of the responsible operator.

(3) The commission may suspend producing and/or drilling operations from any facility when it appears that the provisions of this rule are being violated.

(4) (Reference Order Number 20-60,214, effective October 1, 1970.) The foregoing provisions of Rule 8 (D) shall also be required and enforced as to all oil, gas, or geothermal resource operations conducted on the inland and fresh waters of the State of Texas, such as lakes, rivers, and streams.

(f) Oil and gas waste haulers.

(1) A person who transports oil and gas waste for hire by any method other than by pipeline shall not haul or dispose of oil and gas waste off a lease, unit, or other oil or gas property where it is generated unless such transporter has qualified for and been issued an oil and gas waste hauler permit by the commission. Hauling of inert waste, asbestos-containing material regulated under the Clean Air Act (42 USC §§7401 et seq), polychlorinated biphenyl (PCB) waste regulated under the Toxic Substances Control Act (15 USCA §§2601 et seq), or hazardous oil and gas waste subject to regulation under §3.98 of this title is excluded from this subsection. This subsection is not applicable to the non-commercial hauling of oil and gas wastes for non-commercial recycling. For purposes of this subsection, injection of salt water or other oil and gas waste into an oil and gas reservoir for purposes of enhanced recovery does not qualify as recycling.

(A) Application for an oil and gas waste hauler permit will be made on the commission-prescribed form, and in accordance with the instructions thereon, and must be accompanied by:

(i) the permit application fee required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78);

(ii) vehicle identification information to support commission issuance of an approved vehicle list;

(iii) an affidavit from the operator of each commission-permitted disposal system the hauler intends to use stating that the hauler has permission to use the system; and

(iv) a certification by the hauler that the vehicles listed on the application are designed so that they will not leak during transportation. The certification shall include a statement that vehicles used to haul non-solid oil and gas waste shall be designed to transport non-solid oil and gas wastes, and shall be operated and maintained to prevent the escape of oil and gas waste.

(B) An oil and gas waste hauler permit may be issued for a term not to exceed one year, subject to renewal by the filing of an application for permit renewal and the required application fee for the next permit period. The term of an oil and gas waste hauler permit will be established in accordance with a schedule prescribed by the director to allow for the orderly and timely renewal of oil and gas waste hauler permits on a staggered basis.

(C) Each oil and gas waste hauler shall operate in strict compliance with the instructions and conditions stated on the permit which provide:

(i) This permit, unless suspended or revoked for cause shown, shall remain valid until the expiration date specified in this permit.

(ii) Each vehicle used by a permittee shall be marked on both sides and the rear with the permittee's name and permit number in characters not less than three inches high. (For the purposes of this permit, "vehicle" means any truck tank, trailer tank, tank car, vacuum truck, dump truck, garbage truck, or other container in which oil and gas waste will be hauled by the permittee.)

(iii) Each vehicle must carry a copy of the permit including those parts of the commission-issued attachments listing approved vehicles and commission-permitted disposal systems that are relevant to that vehicle's activities. This permit authority is limited to those vehicles shown on the commission-issued list of approved vehicles.

(iv) This permit is issued pursuant to the information furnished on the application form, and any change in conditions must be reported to the commission on an amended application form. The permit authority will be revised as required by the amended application.

(v) This permit authority is limited to hauling, handling, and disposal of oil and gas waste.

(vi) This permit authorizes the permittee to use commission-permitted disposal systems for which the permittee has submitted affidavits from the disposal system operators stating that the permittee has permission to use the systems. These disposal systems are listed as an attachment to the permit. This permit also authorizes the permittee to use a disposal system operated under authority of a minor permit issued by the commission without submitting an affidavit from the disposal system operator. In addition, this permit authorizes the permittee to transport hazardous oil and gas waste to any facility in accordance with the provisions of §3.98 of this title, provided the shipment is accompanied by a manifest. Finally, this permit authorizes the transportation of oil and gas waste to a disposal facility permitted by another agency or another state provided the commission has granted separate authorization for the disposal.

(vii) The permittee must file an application for a renewal permit, using the permittee's assigned permit number, before the expiration date specified in this permit.

(viii) The permittee must compile and keep current a list of all persons by whom the permittee is hired to haul and dispose of oil and gas waste, and furnish such list to the commission upon request.

(ix) Each vehicle must be operated and maintained in such a manner as to prevent spillage, leakage, or other escape of oil and gas waste during transportation. Vehicles used to haul non-solid oil and gas waste shall be designed to transport non-solid oil and gas wastes, and shall be operated and maintained to prevent the escape of oil and gas waste.

(x) Each vehicle must be made available for inspection upon request by commission personnel.

(2) A record shall be kept by each oil and gas waste hauler showing daily oil and gas waste hauling operations under the permitted authority.

(A) Such daily record shall be dated and signed by the vehicle driver and shall show the following information:

(i) identity of the property from which the oil and gas waste is hauled;

(ii) identity of the disposal system or commercial recycling facility to which the oil and gas waste is delivered;

(iii) the type and volume of oil and gas waste received by the hauler at the property where it was generated; and

(iv) the type and volume of oil and gas waste transported and delivered by the hauler to the disposal system or commercial recycling facility.

(B) Such record shall be kept open for the inspection of the commission or its representatives.

(C) Such record shall be kept on file for a period of three years from the date of operation and recordation.

(g) Recordkeeping.

(1) Oil and gas waste. When oil and gas waste is hauled by vehicle from the lease, unit, or other oil or gas property where it is generated to an off-lease disposal or recycling facility, the person generating the oil and gas waste shall keep, for a period of three years from the date of generation, the following records:

(A) identity of the property from which the oil and gas waste is hauled;

(B) identity of the disposal system or recycling facility to which the oil and gas waste is delivered;

(C) name and address of the hauler, and permit number (WHP number) if applicable; and

(D) type and volume of oil and gas waste transported each day to disposal or recycling.

(2) Retention of run tickets. A person may comply with the requirements of paragraph (1) of this subsection by retaining run tickets or other billing information created by the oil and gas waste hauler, provided the run tickets or other billing information contain all the information required by paragraph (1) of this subsection.

(3) Examination and reporting. The person keeping any records required by this subsection shall make the records available for examination and copying by members and employees of the commission during reasonable working hours. Upon request of the commission, the person keeping the records shall file such records with the commission.

(h) Penalties. Violations of this section may subject a person to penalties and remedies specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the commission. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) (Rule 73) or violation of this section.

(i) Coordination between the Railroad Commission of Texas and the Texas Commission on Environmental Quality or its successor agencies. The Railroad Commission and the Texas Commission on Environmental Quality both have adopted by rule a memorandum of understanding regarding the division of jurisdiction between the agencies over wastes that result from, or are related to, activities associated with the exploration, development, and production of oil, gas, or geothermal resources, and the refining of oil. The memorandum of understanding is adopted in §3.30 of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

(j) Consistency with the Texas Coastal Management Program. The provisions of this subsection apply only to activities that occur in the coastal zone and that are subject to the CMP rules.

(1) Specific Policies.

(A) Disposal of Oil and Gas Waste in Pits. The following provisions apply to oil and gas waste disposal pits located in the coastal zone:

(i) no commercial oil and gas waste disposal pit constructed after the effective date of this subsection shall be located in any CNRA; and

(ii) all oil and gas waste disposal pits shall be designed to prevent releases of pollutants that adversely affect coastal waters or critical areas.

(B) Discharge of Oil and Gas Waste to Surface Waters. The following provisions apply to discharges of oil and gas waste that occur in the coastal zone:

(i) no discharge of oil and gas waste to surface waters may cause a violation of the Texas Surface Water Quality Standards adopted by the Texas Commission on Environmental Quality or its successor agencies and codified at Title 30, Texas Administrative Code, Chapter 307;

(ii) in determining whether any permit to discharge oil and gas waste that is comprised, in whole or in part, of produced water is consistent with the goals and policies of the CMP, the commission shall consider the effects of salinity from the discharge;

(iii) to the greatest extent practicable, in the case of any oil and gas exploration, production, or development operation from which an oil and gas waste discharge commences after the effective date this subsection, the outfall for the discharge shall not be located where the discharge will adversely affect any critical area;

(iv) in the case of any oil and gas exploration, production, or development operation with an oil and gas waste discharge permitted prior to the effective date of this subsection that adversely affects any critical area, the outfall for the discharge shall either:

(I) be relocated within two years after the effective date of this subsection, so that, to the greatest extent practicable, the discharge does not adversely affect any critical area; or

(II) the discharge shall be discontinued; and

(v) the commission shall notify the Texas Commission on Environmental Quality or its successor agencies and the Texas Parks and Wildlife Department upon receipt of an application for a permit to discharge oil and gas waste that is comprised, in whole or in part, of produced waters to waters under tidal influence.

(C) Development in Critical Areas. The provisions of this subparagraph apply to issuance under §401 of the federal Clean Water Act, United States Code, Title 33, §1341, of certifications of compliance with applicable

As in effect on 12/20/2021.

water quality requirements for federal permits authorizing development affecting critical areas. Prior to issuing any such certification, the commission shall confirm that the requirements of Title 31, Texas Administrative Code, §501.14(h)(1)(A) - (G), have been satisfied. The commission shall coordinate its efforts under this subparagraph with those of other appropriate state and federal agencies.

(D) Dredging and Dredged Material Disposal and Placement. The provisions of this subparagraph apply to issuance under §401 of the federal Clean Water Act, United States Code, Title 33, §1341, of certifications of compliance with applicable water quality requirements for federal permits authorizing dredging and dredged material disposal and placement in the coastal zone. Prior to issuing any such certification, the commission shall confirm that the requirements of Title 31, Texas Administrative Code, §501.14(j), have been satisfied.

(2) Consistency Determinations. The provisions of this paragraph apply to issuance of determinations required under Title 31, Texas Administrative Code, §505.30 (Agency Consistency Determination), for the following actions listed in Title 31, Texas Administrative Code, §505.11(a)(3): permits to dispose of oil and gas waste in a pit; permits to discharge oil and gas wastes to surface waters; and certifications of compliance with applicable water quality requirements for federal permits for development in critical areas and dredging and dredged material disposal and placement in the coastal area.

(A) The commission shall issue consistency determinations under this paragraph as an element of the permitting process for permits to dispose of oil and gas waste in a pit and permits to discharge oil and gas waste to surface waters.

(B) Prior to issuance of a permit or certification covered by this paragraph, the commission shall determine if the proposed activity will have a direct and significant adverse effect on any CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to such activity.

(i) If the commission determines that issuance of a permit or a certification covered by this paragraph would not result in direct and significant adverse effects to any CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to the proposed activity, the commission shall issue a written determination of no direct and significant adverse effect which shall read as follows: "The Railroad Commission has reviewed this proposed action for consistency with the Coastal Management Program (CMP) goals and policies, and has found that the proposed action will not have a direct and significant adverse affect on any coastal natural resource area (CNRA) identified in the applicable policies."

(ii) If the commission determines that issuance of a permit or certification covered by this paragraph would result in direct and significant adverse affects to a CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to the proposed activity, the commission shall determine whether the proposed activity would meet the applicable requirements of paragraph (1) of this subsection.

(I) If the commission determines that the proposed activity would meet the applicable requirements of paragraph (1) of this subsection, the commission shall issue a written consistency determination which shall read as follows: "The Railroad Commission has reviewed this proposed action for consistency with the Texas Coastal Management Program (CMP) goals and policies, and has determined that the proposed action is consistent with the applicable CMP goals and policies."

(II) If the commission determines that the proposed activity would not meet the applicable requirements of paragraph (1) of this subsection, the commission shall not issue the permit or certification.

(3) Thresholds for Referral. Any commission action that is not identified in this paragraph shall be deemed not to exceed thresholds for referral for purposes of the CMP rules. Pursuant to Title 31, Texas Administrative Code, §505.32 (Requirements for Referral of an Individual Agency Action), the thresholds for referral of consistency determinations issued by the commission are as follows:

(A) for oil and gas waste disposal pits, any permit to construct a pit occupying five acres or more of any CNRA that has been mapped or that may be readily determined by a survey of the site;

(B) for discharges, any permit to discharge oil and gas waste consisting, in whole or in part, of produced waters into tidally influenced waters at a rate equal to or greater than 100,000 gallons per day;

(C) for certification of federal permits for development in critical areas:

(i) in the bays and estuaries between Pass Cavallo in Matagorda Bay and the border with the Republic of Mexico, any certification of a federal permit authorizing disturbance of:

(I) ten acres or more of submerged aquatic vegetation or tidal sand or mud flats; or

(II) five acres or more of any other critical area; and

(ii) in all areas within the coastal zone other than the bays and estuaries between Pass Cavallo in Matagorda Bay and the border with the Republic of Mexico, any certification of a federal permit authorizing disturbance of five acres or more of any critical area;

(D) for certification of federal permits for dredging and dredged material disposal or placement, certification of a permit authorizing removal of more than 10,000 cubic yards of dredged material from a critical area.

Source Note: The provisions of this §3.8 adopted to be effective January 1, 1976; amended to be effective February 10, 1977, 2 TexReg 359; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective May 1, 1984, 9 TexReg 1549; amended to be effective March 15, 1986, 11 TexReg 950; amended to be effective January 6, 1987, 11 TexReg 5091; amended to be effective December 1, 1987, 12 TexReg 4188; amended to be effective January 28, 1992, 17 TexReg 321; amended to be effective February 1, 1995, 19 TexReg 10345; amended to be effective October 25, 1995, 20 TexReg 8442; amended to be effective April 1, 1996, 20 TexReg 9423; amended to be effective July 10, 2000, 25 TexReg 6487; amended tobe effective September 1, 2004, 29 TexReg 8271; amended to be effective April 15, 2013, 38 TexReg 2318.

§3.9 Disposal Wells

Any person who disposes of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be responsible for complying with this section, Texas Water Code, Chapter 27, and Title 3 of the Natural Resources Code.

(1) General. Saltwater or other oil and gas waste, as that term is defined in the Texas Water Code, Chapter 27, may be disposed of, upon application to and approval by the commission, by injection into nonproducing zones of oil, gas, or geothermal resources bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general uses. Every applicant who proposes to dispose of saltwater or other oil and gas waste into a formation not productive of oil, gas, or geothermal resources must obtain a permit from the commission authorizing the disposal in accordance with this section. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(2) Geological requirements. Before such formations are approved for disposal use, the applicant shall show that the formations are separated from freshwater formations by impervious beds which will give adequate protection to such freshwater formations. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating that the use of such formation will not endanger the freshwater strata in that area and that the formations to be used for disposal are not freshwater-bearing.

(3) Application.

(A) The application to dispose of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be filed with the commission in Austin accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office.

(B) The applicant for a disposal well permit under this section shall include with the permit application a printed copy or screenshot showing the results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

(C) The commission may require an applicant for a disposal well permit under this section to provide the commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS.

(4) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the published notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(5) Notice and opportunity for hearing.

(A) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one-half mile of the proposed disposal well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the municipal boundaries of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(B) In addition to the requirements of subsection (a)(5)(A) of this section, a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed disposal tract by mailing or delivering a copy of the application to each such surface owner.

(C) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water districts.

(D) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(E) Protested applications:

(i) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(ii) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(F) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Subsequent commission action.

(A) A permit for saltwater or other oil and gas waste disposal may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(i) a material change of conditions occurs in the operation or completion of the disposal well, or there are material changes in the information originally furnished;

(ii) freshwater is likely to be polluted as a result of continued operation of the well;

(iii) there are substantial violations of the terms and provisions of the permit or of commission rules;

(iv) the applicant has misrepresented any material facts during the permit issuance process;

(v) injected fluids are escaping from the permitted disposal zone;

(vi) injection is likely to be or determined to be contributing to seismic activity; or

(vii) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(B) A disposal well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on Commission records.

(C) Voluntary permit suspension.

(i) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of paragraph (12)(D) of this section. The provisions of this subparagraph shall not apply to any well that is permitted as a commercial disposal well.

(ii) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under clause (i) of this subparagraph indicate that the well meets the performance standards of paragraph (12)(D) of this section.

(iii) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(iv) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of paragraph (12)(D) of this section or the permit. Further, during the period of permit suspension, the provisions of paragraph (11)(A) - (C) of this section shall not apply.

(v) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of paragraph (12)(D) of this section.

(7) Area of Review.

(A) Except as otherwise provided in this paragraph, the applicant shall review the date of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(B) The commission or its delegate may grant a variance from the area-of-review requirements of subparagraph (A) of this paragraph upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(i) the area affected by pressure increases resulting from injection operations;

(ii) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(iii) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(C) Persons applying for a variance from the area-of-review requirements of subparagraph (A) of this paragraph on the basis of factors set out in subparagraph (B)(ii) or (iii) of this paragraph for an individual well shall provide notice of the application to those persons given notice under the provisions of paragraph (5)(A) of this subsection. The provisions of paragraph (5)(D) and (E) shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(D) Notice of an application for an areal variance from the area-of-review requirements under subparagraph (A) of this paragraph shall be given on or before the date the application is filed with the commission:

(i) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(ii) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date of the application is filed with the commission, to the following:

(I) the manager of each underground water conservation district(s) in which the variance would apply, if any;

(II) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(III) the county clerk of each county in which the variance would apply; and

(IV) any other person or persons that the commission or its delegate determine should receive notice of the application.

(E) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(F) An areal variance granted under the provisions of this paragraph may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under subparagraph (A) of this paragraph pending issuance of a final order.

(8) Casing. Disposal wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, geothermal resources, or freshwater resources.

(9) Special equipment.

(A) Tubing and packer. Wells drilled or converted for disposal shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 100 feet above the top of the permitted interval. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

(B) Pressure valve. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(C) Exceptions. The director may grant an exception to any provision of this paragraph upon proof of good cause. If the director denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(10) Well record. Within 30 days after the completion or conversion of a disposal well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(11) Monitoring and reporting.

(A) The operator shall monitor the injection pressure and injection rate of each disposal well on at least a monthly basis, or on a more frequent basis as required by the commission under conditions described in paragraph (3)(C) of this section.

(B) The results of the monitoring shall be reported annually to the commission on the prescribed form, or on a more frequent basis as required by the commission under conditions described in paragraph (3)(C) of this section.

(C) All monitoring records shall be retained by the operator for at least five years.

(D) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(12) Testing.

(A) Purpose. The mechanical integrity of a disposal well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under subparagraph (E) of this paragraph.

(B) Applicability. Mechanical integrity of each disposal well shall be demonstrated in accordance with provisions of subparagraph (D) and subparagraph (E) of this paragraph prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in subparagraph (C) of this paragraph.

(C) Frequency.

(i) Each disposal well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(ii) In addition to testing required under clause (i), each disposal well shall be tested for mechanical integrity after every workover of the well.

(iii) A disposal well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the disposal well permit.

(iv) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in clauses (i) and (ii) of this subparagraph. Such testing schedule shall not apply to a disposal well for which a disposal well permit has been issued but the well has not been drilled or converted to disposal.

(D) Pressure tests.

(i) Test pressure.

(I) The test pressure for wells equipped to dispose through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(II) The test pressure for wells that are permitted for disposal through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(ii) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in clause (i) of this subparagraph prior to commencement of the test.

(iii) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(iv) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(v) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for disposal through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(vi) Test fluid.

(I) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes the use of a different test fluid for good cause.

(II) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(vii) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(I) the degree of pressure change during the test, if any;

(II) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(III) whether circumstances surrounding the administration of the test make the test inconclusive.

(E) Alternative testing methods.

(i) As an alternative to the testing required in subparagraph (B) of this paragraph, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by paragraph (11) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under subparagraph (B) of this paragraph at least once every ten years after January 1, 1990.

(ii) The commission or its delegate may grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(F) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(G) A complete record of all tests shall be filed in duplicate in the district office on the appropriate form within 30 days after the testing.

(H) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(13) Plugging. Disposal wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(14) Penalties.

(A) Violations of this section may subject the operator to penalties and remedies specified in the Texas Water Code, Chapter 27, and the Natural Resources Code, Title 3.

(B) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certification of Compliance; Severance) for violation of this section.

Source Note: The provisions of this §3.9 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective April 1, 1982, 7 TexReg 651; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective November 17, 2014, 39 TexReg 8988.

§3.10 Restriction of Production of Oil and Gas from Different Strata

(a) General prohibition. Oil or gas shall not be produced from different strata through the same string of tubulars except as provided in this section. As used in this section, "different strata" means two or more different commission-designated fields, or one or more commission-designated fields and any other hydrocarbon reservoir.

(b) Exception. After notice and an opportunity for a hearing, the commission or its delegate may grant an exception to subsection (a) of this section to permit production from a well or wells commingling oil or gas or oil and gas from different strata, if commingled production will prevent waste or promote conservation or protect correlative rights.

(c) Notice of Application for Exception.

(1) Timing of Notice.

(A) The applicant shall give notice of each request for an exception by serving a copy of the application to commingle production on all affected operators at the same time the application is filed with the commission.

(B) Service shall be accomplished by delivering a copy of the application to the operator to be served, or to the operator's duly authorized representative, in person, by agent, by courier receipted delivery, by first class mail to the operator's mailing address as shown on the operator's most recently filed Form P-5 (Organization Report) or the most recently filed letter notification of change of address, or by such other manner as the commission may direct.

(2) Operators Presumptively Affected By Application.

(A) An initial exception to commingle production exclusively from different commission-designated fields is or limit the commission, acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with the commission rules and regulations.

(f) Penalties.

(1) False reports. The filing of a false or incorrect directional survey shall be grounds for cancellation of the well permit, for pipeline severance of the lease on which the well is located, for penalty action under the applicable statutes, and/or for such other and further action as may be appropriate.

(2) Other. The same penalties and actions as set forth in paragraph (1) of this subsection shall be assessable against any operator who refuses to comply with a commission order which issues under subsection (c) of this section.

Source Note: The provisions of this §3.11 adopted to be effective January 1, 1976; amended to be effective July 4, 1979, 4 TexReg 2197; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective June 11, 2001, 26 TexReg 4088.

§3.12 Directional Survey Company Report

(a) For each well drilled for oil, gas, or geothermal resources for which a directional survey report is required by rule, regulation, or order, the surveying company shall prepare and file the following information. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

(1) the name of the surveying company;

(2) the name of the individual performing the survey for the surveying company;

(3) the title or position the individual holds with the surveying company;

(4) the date on which the individual performed the survey;

(5) the type of survey conducted and whether the survey was multishot;

(6) a complete identification of the well, including the name of the operator of the well; the fee owner; the commission lease number, if assigned; the well number; the API number, and the drilling permit number, the land survey; the field name; and the county and state; and

(7) a notation that the survey was conducted from a depth of ____ feet to ____ feet.

(b) Each directional survey, with its accompanying certification and a certified plat on which the bottom hole location is oriented both to the surface location and to the lease lines (or unit lines in case of pooling) shall be mailed by registered, certified, or overnight mail direct to the commission in Austin by the surveying company making the survey. The surveying company may file electronically if the Commission has provided for such filing.

Source Note: The provisions of this §3.12 adopted to be effective January 1, 1976; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective October 27, 2008, 33 TexReg 8785.

§3.13 Casing, Cementing, Drilling, Well Control, and Completion Requirements

(a) General. Operators shall comply with this section for any wells that will be spudded on or after January 1, 2014.

(1) Intent. The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. In accordance with §3.17 of this title (relating to Pressure on Bradenhead), operators must notify the Commission of bradenhead pressure. The Commission will evaluate notices of bradenhead pressure on a case-by-case basis to determine further action and will provide guidance to assist operators in wellbore evaluation.

(2) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar and/or float shoe is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--

(i) For surface casing strings, the bottom 20% of the casing string, but no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(ii) For intermediate or production casing strings, the bottom 20% of the casing string or 300 vertical feet above the casing shoe or top of the highest proposed productive zone, whichever is less.

(C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive zone--Any stratum known to contain oil, gas, or geothermal resources in commercial quantities in the area.

(E) Gas/oil contact zone--A zone in an oil well in which natural gas, commonly known as gas cap gas, overlies and is in contact with crude oil in a reservoir.

(F) Bay well--Any well under the jurisdiction of the Commission as defined in §3.78(a)(5) of this chapter.

(G) Deputy director of Field Operations--The deputy director of Field Operations of the Oil and Gas Division or the deputy director's delegate.

(H) Director--The director of the Oil and Gas Division of the Railroad Commission of Texas or the director's delegate.

(I) District director--The Director of a Railroad Commission district office or the district director's delegate.

(J) Hydraulic fracturing treatment--A completion process involving treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas. The term does not include acid treatment, perforation, or other non-fracture treatment completion activities.

(K) Land well--Any well subject to Commission jurisdiction as defined in §3.78(a)(6) of this chapter.

(L) Minimum separation well--A well in which hydraulic fracturing treatments will be conducted and for which:

(i) the vertical distance between the base of usable quality water and the top of the formation to be stimulated is less than 1,000 vertical feet;

(ii) the director has determined contains inadequate separation between the base of usable quality water and the top of the formation in which hydraulic fracturing treatments will be conducted; or

(iii) the director has determined is in a structurally complex geologic setting.

(M) Offshore well--Any well subject to Commission jurisdiction as defined by §3.78(a)(7).

(N) Potential flow zone--A zone designated by the director or identified by the operator using available data that needs to be isolated to prevent sustained pressurization of the surface casing/intermediate casing or production casing annulus sufficient to cause damage to casing and/or cement in a well such that it presents a threat to subsurface water or oil, gas, or geothermal resources. The Commission will maintain a list of known zones by district and county that are considered potential flow zones and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

(O) Zone with corrosive formation fluids--Any zone designated by the director or identified by the operator using available data containing formation fluids that are capable of negatively impacting the integrity of casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field. The Commission will maintain a list of known zones by district and county that are considered zones with corrosive formation fluids, and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

(P) Usable quality water--Water as defined in §3.30(e)(7)(B)(i) of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

(3) Wellbore diameters.

(A) The diameter of the wellbore in which surface casing will be set and cemented shall be at least one and one-half (1.50) inches greater than the nominal outside diameter of casing to be installed, unless otherwise approved by the district director.

(B) For subsequent casing strings, the diameter of each section of the wellbore for which casing will be set and cemented shall be at least one (1) inch greater than the nominal outside diameter of the casing to be installed, unless otherwise approved by the district director. The district director may grant such approvals on an area basis.

(C) The casing diameter requirements in subparagraphs (A) and (B) of this paragraph do not apply to reentries, liners, and expandable casing.

(D) All float equipment, centralizers, packers, cement baskets, and all other equipment run into the wellbore on casing shall be consistent with the manufacturer's recommendations.

(4) Casing and cementing.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a casing evaluation tool may be employed. Casing meeting the performance standards set forth in API Specification 5CT: Specification for Casing and Tubing (or a Commission-approved equivalent standard) shall be used through the protection depth.

(B) The base cement shall meet the standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement (or a Commission-approved equivalent standard).

(C) Casing shall be cemented across and above all formations permitted for injection under §3.9 of this title (relating to Disposal Wells) at the time the well is completed, or cemented immediately above all formations permitted for injection under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) at the time the well is completed, in a well within one-quarter mile of the proposed well location, as follows:

(i) if the top of cement is determined through calculation, at least 600 feet (measured depth) above the permitted formations;

(ii) if the top of cement is determined through the performance of a temperature survey conducted immediately after cementing, 250 feet (measured depth) above the permitted formations;

(iii) if the top of cement is determined through the performance of a cement evaluation log, 100 feet (measured depth) above the permitted formations;

(iv) at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(D) Casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids, as follows:

(i) if the top of cement is determined through calculation, across and extending at least 600 feet (measured depth) above the zones;

(ii) if the top of cement is determined through the performance of a temperature survey, across and extending 250 feet (measured depth) above the zones;

(iii) if the top of cement is determined through the performance of a cement evaluation log, across and extending 100 feet (measured depth) above the zones;

(iv) across and extending at least 200 feet into the previous casing shoe (or to the surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(E) Where necessary, the cement slurry shall be designed to control annular gas migration consistent with, or equivalent to, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.

(5) Casing testing before drillout. For surface and intermediate strings of casing, before drilling the cement plug, the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot. The maximum test pressure required, however, unless otherwise ordered by the Commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation that the condition has been corrected. The operator shall notify the district director of a failed test. In the event of a pressure test failure, completion operations may not re-commence until the district director approves a remediation plan, the operator successfully implements the plan, and the operator conducts a successful pressure test.

(6) Well control.

(A) Wellhead assemblies. After setting the conductor pipe on offshore wells or surface casing on land or bay wells, wellhead assemblies shall be used on wells to maintain surface control of the well at all times. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(B) Well control equipment.

(i) An operator shall install a blowout preventer system or control head and other connections to keep the well under control at all times as soon as surface casing is set. When conductor casing is set and/or shallow gas is anticipated to be encountered, operators shall install a diverter system on the conductor casing. For bay and offshore wells, at a minimum, such systems shall include a double ram blowout preventer, including pipe and blind rams, an annular-type blowout preventer or other equivalent control system, and a shear ram.

(ii) For wells in areas with hydrogen sulfide, the operator shall comply with §3.36 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

(iii) Ram type blowout prevention equipment shall have a rated working pressure that equals or exceeds the maximum anticipated surface pressure of the well. Blowout preventer rams shall be of a proper size for the drill pipe being used or production casing being run in the well or shall be variable-type rams that are in the appropriate size range. Alternatively, an annular preventer may be used in lieu of casing/pipe rams or variable bore rams when running production casing provided the expected shut-in surface pressures would not exceed the tested pressure rating of the annular preventer.

(iv) Operators shall install a drill pipe safety valve to prevent backflow of water, oil, gas, or other formation fluids into the drill string.

(v) Operators shall install a choke line of sufficient size and working pressure.

(vi) When using a Kelly rig during drilling, the well shall be fitted with an upper Kelly cock in proper working order to close in the drill string below hose and swivel, when necessary for well control. A lower Kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(I) full-opening safety valve; and

(II) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use.

(vii) All control equipment shall be consistent with API Standard 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells. Control equipment shall be certified in accordance with API Standard 53 as operable under the product manufacturer's minimum operational specifications. Certification shall include the proper operation of the closing unit valving, the pressure gauges, and the manufacturer's recommended accumulator fluids. Certification shall be obtained through an independent company that tests blowout preventers, stacks and casings. Certification shall be performed every five (5) years and the proof of certification shall be made available upon request of the Commission.

(viii) All well control equipment shall be in good working condition at all times. All outlets, fittings, and connections on the casing, blowout preventers, choke manifold, and auxiliary wellhead equipment that may be subjected to wellhead pressure shall be of a material and construction to withstand or exceed the anticipated pressure. The lines from outlets on or below the blowout preventers shall be securely installed, anchored, and protected from damage.

(ix) In addition to the primary closing system, including an accumulator system, the blowout preventers shall have a secondary location for closure.

(x) Testing of blowout prevention equipment.

(I) Ram type blowout prevention equipment shall be tested to at least the maximum anticipated surface pressure of the well, but not less than 1,500 psi, before drilling the plug on the surface casing.

(II) Blowout prevention equipment shall be tested upon installation, after the disconnection or repair of any pressure containment seal in the blowout preventer stack, choke line, or choke manifold, limited to the affected component, with testing to occur at least every 21 days. When requested, the district director shall be notified before the commencement of a test.

(III) A record of each test, including test pressures, times, failures, and each mechanical test of the casings, blowout preventers, surface connections, surface fittings, and auxiliary wellhead equipment shall be entered in the logbook, signed by the person responsible for the test, and made available for inspection by the Commission upon request.

(C) Drilling fluid program.

(i) The characteristics, use, and testing of drilling fluid and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics shall be maintained. Drilling fluid tests shall be performed as needed to ensure well control. Adequate drilling fluid testing equipment shall be kept on the drilling location at all times. Sufficient drilling fluid shall be pumped and maintained to ensure well control at all times, including when pulling drill pipe. Mud pit levels shall be visually or mechanically monitored during the drilling process. Mud-gas separation equipment shall be installed and operated as needed when abnormally pressured gas-bearing formations may be encountered. The Commission shall have access to the drilling fluid records and shall be allowed to conduct any essential tests on the drilling fluid used in the drilling or recompletion of a well. When the conditions and tests indicate a need for a change in the drilling fluid program in order to insure control of the well, the operator shall use due diligence in modifying the program.

(ii) Wells drilled with air shall maintain well control using blowout preventer systems and/or diverter systems.

(iii) All hole intervals drilled prior to reaching the base of protected water shall be drilled with air, fresh water or a fresh water based drilling fluid. No oil-based drilling fluid may be used until casing has been set and cemented to the protection depth.

(D) Diverter systems for bay and offshore wells. Any bay or offshore well that is drilled to and/or through formations where the expected reservoir pressure exceeds the hydrostatic pressure of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. When the diverter system is installed, the diverter components including the sealing element, diverter valves, control systems, stations and vent lines shall be function and pressure tested. For drilling operations with a surface wellhead configuration, the system shall be function tested at least once every 24-hour period after the initial test. After all connections have been made on the surface casing or conductor casing, the diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psig. Subsequent pressure tests shall be conducted within seven days after the previous test. All diverter systems shall be maintained in working condition. No operator shall continue drilling operations if a test or other information indicates that the diverter system is unable to function or operate as designed.

(E) Casinghead.

(i) Requirements. All land and bay wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves accessible at the surface, to allow pumping of fluid between any two strings of casing at the surface.

(ii) Casinghead test procedure. Any well showing sustained pressure on the casinghead, or leaking gas or oil between the surface casing and the next casing string, shall be tested in the following manner. The well shall be killed with water or mud and pump pressure applied. The casing shall be condemned if the pressure gauge on the casinghead reflects the applied pressure. After completing corrective measures, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot otherwise be determined.

(F) Christmas tree.

(i) All completed non-pumping wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valve, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed.

(ii) The Christmas tree for completed bay and offshore wells shall be equipped with either two master valves, one master valve and one wing valve, or two wing valves. All bay and offshore wells shall have at least five feet of spacing between the bottom of the Christmas tree and the surface of the water at high tide, where applicable. Any newly completed bay and offshore well or existing well on which the Christmas tree is being replaced shall be equipped with a back pressure valve wellhead profile at the flange where the tubing hangs on the Christmas tree.

(G) Storm choke and safety valve.

(i) Bay and offshore wells shall be equipped with a storm choke and/or safety valve installed in the tubing.

(ii) An operator may request approval to use a surface safety valve in lieu of a subsurface safety valve by filing with the appropriate district director a written request for such approval providing all pertinent information to support the exception.

(iii) The depth and type of the safety valve shall be reported in the "remarks" section of the appropriate completion report form required by §3.16 of this title (relating to Log and Completion or Plugging Report), after the well is completed or recompleted.

(7) Additional requirements for wells on which hydraulic fracturing treatments will be conducted.

(A) All casing strings or fracture tubing installed in a well that will be subjected to hydraulic fracturing treatments shall have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing strings or fracture tubing may be subjected.

(B) The operator shall pressure test the casing (or fracture tubing) on which the pressure will be exerted during hydraulic fracturing treatments to at least the maximum pressure allowed by the completion method. Casing strings that include a pressure actuated valve or sleeve shall be tested to 80 percent of actuation pressure for a minimum time period of five (5) minutes. A surface pressure loss of greater than 10 percent of the initial test pressure is considered a failed test. The casing required to be pressure tested shall be from the wellhead to at least the depth of the top of cement behind the casing being tested. The district director shall be notified of a failed test within 24 hours of completion of the test. In the event of a pressure test failure, no hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(C) During hydraulic fracturing treatment operations, the operator shall monitor all annuli. The operator shall immediately suspend hydraulic fracturing treatment operations if the pressures deviates above those anticipated increases caused by pressure or thermal transfer and shall notify the appropriate district director within 24 hours of such deviation. Further completion operations, including hydraulic fracturing treatment operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(D) The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director:

(i) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface).

(ii) The operator shall pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatment. The operator shall notify the district director within 24 hours of a failed test. No hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(iii) The production casing for any minimum separation well shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.

(iv) In addition to conducting an evaluation of cementing records and annular pressure monitoring results, the operator of a minimum separation well shall run a cement evaluation tool to assess radial cement integrity and placement behind the production casing. If the cement evaluation indicates insufficient isolation, completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(v) The operator of a minimum separation well may request from the appropriate district director approval of an exemption from the requirement to run a cement evaluation tool. Such request shall include information demonstrating that the operator has:

(I) successfully set, cemented, and tested the casing for which the exemption is requested in at least five minimum separation wells by the same operator in the same operating field;

(II) obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results or other tests demonstrating that successful cement placement was achieved to isolate productive zones, potential flow zones, and/or zones with corrosive formation fluids; and

(III) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the five wells that have had successful cement jobs.

(8) Pipeline shut-off valves for bay and offshore wells. All bay and offshore gathering pipelines designed to transport oil, gas, condensate, or other oil or geothermal resource field fluids from a well or platform shall be equipped with automatically controlled shut-off valves at critical points in the pipeline system. Other safety equipment shall be in full working order as a safeguard against spillage from pipeline ruptures.

(9) Training for bay and offshore wells. All tool pushers, drilling superintendents, and operators' representatives (when the operator is in control of the drilling) shall be required to, upon request, furnish certification of satisfactory completion of an American Petroleum Institute (API) training program, an International Association of Drilling Contractors (IADC) training program, or other equivalent nationally recognized training program on well control equipment and procedures. The certification shall be renewed every two years by attending an API- or IADC-approved refresher course or a refresher course approved by the equivalent nationally recognized training program.

(10) Bottom-hole pressure surveys. The Commission may require bottom-hole pressure surveys of the various fields at such times as determined to be necessary. However, operators shall be required to take bottom-hole pressures only in those wells that are not likely to suffer damaging effects from the survey. Tubing and tubingheads shall be free from obstructions in wells used for bottom-hole pressure test purposes.

(b) Casing and cementing requirements for land wells and bay wells.

(1) Surface casing requirements for land wells and bay wells.

(A) Any proposal to set surface casing to a depth of 3,500 feet or greater shall require prior approval of the appropriate district director. A request for such approval shall be in writing and shall specify how the operator plans to maintain well control during drilling, and ensure successful circulation and adequate bonding of cement, and, if necessary, prevent upward migration of deeper formation fluids into protected water. The district director may grant approvals on an area basis.

(B) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. The district director may grant such approval on an area basis.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(C) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or the operator's representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(D) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement.

(iv) The Commission may require a better quality of cement mixture to be used in any well or any area if conditions indicate that a better quality of cement is necessary to prevent pollution, isolate productive zones, potential flow zones, or zones with corrosive formation fluids or prevent a safety issue in the well.

(E) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

As in effect on 12/20/2021.

(F) Cementing report. Within 30 days of completion of the well, or within 90 days of cessation of drilling operations, whichever is earlier, a cementing report must be filed with the Commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the Commission. The operator of the well or the operator's duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the Commission.

(G) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet specifications in, or equivalent to, API spec 10D Specifications for Bow-Spring Casing Centralizers; API Spec 10 TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations; and API RP 10D-2, Recommended Practice for Centralizer Placement and Stop Collar Testing.

(H) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be considered on an individual well basis only. The district director may approve, modify, or reject the proposed program. The district director shall deny the request if the operator has not demonstrated that the alternative casing plan will achieve the intent of this rule as described in subsection (a)(1) of this section. If the proposal is modified or rejected, the operator may request a review by the deputy director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 100 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or the operator's representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the Commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(I) Mechanical integrity test of surface casing after drillout.

(i) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the operator shall verify the integrity of the surface casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent Commission-approved casing evaluation method, unless otherwise approved by the district director.

(ii) If a mechanical integrity test is conducted, the appropriate district office shall be notified at least eight hours before the test is conducted to give the district office an opportunity to witness the test. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. The appropriate district office shall be notified within 24 hours after a failed test. Completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan, and successfully re-tests the surface casing.

(2) Intermediate casing requirements for land wells and bay wells.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented:

(i) if the top of cement is determined through calculation, from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;

(ii) if the top of cement is determined through performance of a temperature survey, from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;

(iii) if the top of cement is determined through performance of a cement evaluation log, from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or

(iv) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(B) Top of cement. The calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title (relating to Log and Completion or Plugging Report).

(C) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone, and/or zone with corrosive formation fluids make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively isolate and seal the zones to prevent fluid migration to or from such strata within the wellbore.

(3) Production casing requirements for land wells and bay wells.

(A) Centralizers. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation.

(B) Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the Commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive zone, potential flow zone and/or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing in paragraph (2) of this subsection. A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating casing pressure tests. In the event that the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone and/or zone with corrosive formation fluids make cementing, as required above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such zones, and prevent fluid migration to or from such zones within the wellbore.

Uncemented casing is allowable within a producing reservoir provided the production casing is cemented in such a manner to effectively isolate and seal off that zone from all other productive zones in the wellbore as required by §3.7 of this title (relating to Strata To Be Sealed Off).

(C) Reporting of top of cement. Calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title.

(D) Isolation of gas/oil contact zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(4) Tubing requirements for land wells and bay wells.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet (vertical depth) above the top of the producing interval nor more than 50 feet (vertical depth) above the top of the liner, if a liner is used, or 100 feet (vertical depth) above the kickoff point in a deviated or horizontal well. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet (vertical depth) above the top of the perforated or open-hole interval actually open for production into the wellbore.

(B) Alternate tubing requirements. Alternate programs requesting a temporary exception pursuant to subsection (d) of this section to omit tubing from a flowing oil well may be authorized on an individual well basis by the appropriate district director. The district director shall deny the request if the operator has not demonstrated that the alternative tubing plan will achieve the intent as described in subsection (a)(1) of this section. If the proposal is rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a hearing. An operator shall obtain approval of any alternative program before commencing operations.

(c) Casing, cementing, drilling, and completion requirements for offshore wells.

(1) Casing. An offshore well shall be cased with at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program.

(A) Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be used to fill the annular space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.

(B) Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows.

(i) Surface Casing Depth Table.

Proposed Total Vertical Depth of Well	Surface
to 7,000 feet	25% of proposed total depth of well
7,000 - 10,000 feet	2,000 feet
10,000 and below	2,500 feet

(ii) Surface Casing test.

(I) Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes constitutes confirmation that the condition has been corrected.

(II) After drillout, if the surface casing is exposed to more than 360 rotating hours, the operator shall verify the integrity of the casing using a casing evaluation tool, a mechanical integrity test, or an equivalent Commission-approved alternate casing evaluation methodology, unless otherwise approved by the district director.

(III) If a mechanical integrity test of the surface casing is conducted, the appropriate district office shall be notified a minimum of eight (8) hours before the test is conducted. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a minimum test pressure of 0.5 psi per foot multiplied by the true vertical depth of the surface casing up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% drop in pressure after 30 minutes constitutes confirmation of an acceptable pressure test. The operator shall notify the appropriate district office within 24 hours of a failed test. Operations may not re-commence until the district director approves a remediation plan and the operator implements the approved plan, and the operator successfully re-tests the surface casing.

(C) Production casing or oil string.

(i) The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure.

(ii) After cementing, the production casing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner.

(iii) Cementing of the production casing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to isolate any productive zones, potential flow zones, or zones with corrosive formation fluids and to a depth that isolates abnormal pressure from normal pressure (0.465 psi per vertical foot of gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

(2) Operators shall comply with the well control requirements of subsection (a)(6) of this section.

(d) Exceptions or alternate programs. The director may administratively grant an exception or approve an alternate casing/tubing program required by this section provided that the alternate casing/tubing program will achieve the intent of the rule as described in subsection (a)(1) of this section and the following requirements are met:

(1) The request for an exception or alternate casing/tubing program shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception for tubing shall not exceed a period of 180 days. A request for an exception for tubing beyond 180 days shall require a Commission order.

Source Note: The provisions of this §3.13 adopted to be effective January 1, 1976; amended to be effective April 8, 1980, 5 TexReg 1152; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective January 1, 1983, 7 TexReg 3982; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective January 11, 1991, 16 TexReg 39; amended to be effective August 13, 1991, 16 TexReg 4153; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective January 1, 2014, 38 TexReg 3542.

§3.14 Plugging

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Approved cementer--A cementing company, service company, or operator approved by the Commission or its delegate to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission or its delegate to use an alternate material other than cement to plug a well.

(B) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(C) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(D) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter that has been completed, signed, and filed with the Commission or its delegate.

(E) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(F) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(G) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission or its delegate on Form PR, Monthly Production Report.

(H) Serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(I) Usable quality water strata--All strata determined by the Groundwater Advisory Unit of the Oil and Gas Division to contain usable quality water.

(J) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(c)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on Commission Form P-13, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party

cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed unless the Commission or its delegate approves a plugging extension under §3.15 of this title (relating to Surface Equipment Removal Requirements and Inactive Wells).

(3) The Commission may plug or replug any dry or inactive well as follows:

(A) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if oil, gas, or other formation fluid is leaking from the well, and:

(i) neither the operator nor any other entity responsible for plugging the well can be found; or

(ii) neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(B) Without a hearing if the well is a delinquent inactive well and:

(i) the Commission has sent notice of its intention to plug the well as required by §89.043(c) of the Texas Natural Resources Code; and

(ii) the operator did not request a hearing within the period (not less than 10 days after receipt) specified in the notice.

(C) Without notice or hearing, if:

(i) the Commission has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(ii) the well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(4) The Commission may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to paragraph (3) of this subsection.

(c) Designated operator responsible for proper plugging.

(1) The entity designated as the operator of a well specifically identified on the most recent Commission-approved operator designation form filed on or after September 1, 1997, is responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells.

(2) As to any well for which the most recent Commission-approved operator designation form was filed prior to September 1, 1997, the entity designated as operator on that form is presumed to be the entity responsible for the physical operation and control of the well and to be the entity responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells. The presumption of responsibility may be rebutted only at a hearing called for the purpose of determining plugging responsibility.

(d) General plugging requirements.

(1) Wells shall be plugged to insure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall not be an employee of the service or cementing company hired to plug the well. Direct supervision means supervision at the well site during the plugging operations. The operator and the cementer are both responsible for complying with the general plugging requirements of this subsection and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged. The operator and cementer may each be assessed administrative penalties for failure to comply with the general plugging requirements of this subsection or for failure to plug the well in conformity with the approved notice of intention to plug and abandon the well.

(2) Cement plugs shall be set to isolate each productive horizon and usable quality water strata. Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division. The operator shall verify the placement of the plug required at the base of the deepest usable quality water stratum by tagging with tubing or drill pipe or by an alternate method approved by the district director or the district director's delegate.

(3) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe. Cement plugs shall be placed by other methods only upon written request with the written approval of the district director or the director's delegate.

(4) All cement for plugging shall be an approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the cementing report. The district director or the director's delegate may require that specific cement compositions be used in special situations; for example, when high temperature, salt section, or highly corrosive sections are present. An operator shall request approval to use alternate materials, other than API oil well cement without volume extenders, to plug a well by filing with the director or the director's delegate a written request

providing all pertinent information to support the use of the proposed alternate material and plugging method. The director or the director's delegate shall determine whether such a request warrants approval, after considering factors which include but are not limited to whether or not the well to be plugged was used as an injection or disposal well; the well's history; the well's current bottom hole pressure; the presence of highly pressurized formations intersected by the wellbore; the method by which the alternative material will be placed in the wellbore; and the compressive strength and other performance specifications of the alternative material to be used. The director or the director's delegate shall approve such a request only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

(5) Operators shall use only cementers approved by the director or the director's delegate, except when plugging is conducted in accordance with subparagraph (B)(ii) of this paragraph or paragraph (6) of this subsection. Cementing companies, service companies, or operators may apply for designation as approved cementers. Approval will be granted on a showing by the applicant of the ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this rule. An approved cementer is authorized to conduct plugging operations in accordance with Commission rules in each Commission district.

(A) A cementing company, service company, or operator seeking designation as an approved cementer shall file a request in writing with the district director of the district in which it proposes to conduct its initial plugging operations. The request shall contain the following information:

(i) the name of the organization as shown on its most recent approved organizational report;

(ii) a list of qualifications including personnel who will supervise mixing and pumping operations;

(iii) length of time the organization has been in the business of cementing oil and gas wells;

(iv) an inventory of the type of equipment to be used to mix and pump cement or other alternate materials as approved by the director or the director's delegate; and

(v) a statement certifying that the organization will comply with all Commission rules.

(B) No request for designation as an approved cementer will be approved until after the district director or the director's delegate has:

(i) inspected all equipment to be used for mixing and pumping cement or other alternate materials as approved by the director or the director's delegate; and

(ii) witnessed at least one plugging operation to determine if the cementing company, service company, or operator can properly mix and pump cement or other alternate materials as approved by the director or the director's delegate according to the specifications required by this rule.

(C) The district director or the director's delegate shall file a letter with the director or the director's delegate recommending that the application to be designated as an approved cementer be approved or denied. If the district director or the director's delegate does not recommend approval, or the director or the director's delegate denies the application, the applicant may request a hearing on its application.

(D) Designation as an approved cementer may be suspended or revoked for violations of Commission rules. The designation may be revoked or suspended administratively by the director or the director's delegate for violations of Commission rules if:

(i) the cementer has been given written notice by personal service or by registered or certified mail informing the cementer of the proposed action, the facts or conduct alleged to warrant the proposed action, and of its right to request a hearing within 10 days to demonstrate compliance with Commission rules and all requirements for retention of designation as an approved cementer; and

(ii) the cementer did not file a written request for a hearing within 10 days of receipt of the notice.

(6) An operator may request administrative authority to plug its own wells without being an approved cementer. An operator seeking such authority shall file a written request with the district director and demonstrate its ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this subsection. The district director or the director's delegate shall determine whether such a request warrants approval. If the district director or the director's delegate refuses to administratively approve this request, the operator may request a hearing on its request.

(7) The district director or the director's delegate may require additional cement plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting may be required if necessary to ensure that the well does not pose a potential threat of harm to natural resources.

(8) For onshore or inland wells, a 10-foot cement plug shall be placed in the top of the well, and casing shall be cut off three feet below the ground surface.

(9) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by the director or the director's delegate. The hole shall be in static condition at the time the cement plugs are placed. The district director

or the director's delegate may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will insure that the well does not pose a potential threat of harm to natural resources. An operator shall request approval to use alternate fluid other than mud-laden fluid by filing with the district director a written request providing all pertinent information to support the use of the proposed alternate fluid. The district director or the director's delegate shall determine whether such a request warrants approval, and shall approve such a request only if the proposed alternate fluid will insure that the well does not pose a potential threat of harm to natural resources.

(10) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except in the case of a well plugged and abandoned under the provisions of §3.35 or §4.614(b) of this title (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned (Statewide Rule 35); and Authorized Disposal Methods, respectively). Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the district director or the director's delegate.

(11) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(12) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits in accordance with the provisions of §3.8 of this title (relating to Water Protection (Statewide Rule 8)). The district director or the director's delegate may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

(e) Plugging requirements for wells with surface casing.

(1) When insufficient surface casing is set to protect all usable quality water strata and such usable quality water strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and 50 feet below the base of the deepest usable quality water stratum. This plug shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug shall be set across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe.

(2) When sufficient surface casing has been set to protect all usable quality water strata, a cement plug shall be placed across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above the shoe and at least 50 feet below the shoe.

(3) If surface casing has been set deeper than 200 feet below the base of the deepest usable quality water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest usable quality water stratum. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(4) Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(5) An operator may not remove, cause to be removed, or allow to be removed surface casing from a well at abandonment. This prohibition applies to wells drilled by cable tool and rotary rigs alike.

(f) Plugging requirements for wells with intermediate casing.

(1) For wells in which the intermediate casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum, but extend no less than 50 feet above and below the base of the deepest usable quality water stratum.

(2) For wells in which intermediate casing is not cemented through all usable quality water strata and all productive horizons, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(g) Plugging requirements for wells with production casing.

(1) For wells in which the production casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum and across any multi-stage cementing tool. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(2) For wells in which the production casing has not

been cemented through all usable quality water strata and all productive horizons and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) The district director or the director's delegate may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(4) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(h) Plugging requirements for well with screen or liner.

(1) If practical, the screen or liner shall be removed from the well.

(2) If the screen or liner is not removed, a cement plug in accordance with subsection (d)(11) of this section shall be placed at the top of the screen or liner.

(i) Plugging requirements for wells without production casing and open-hole completions.

(1) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in subsection (d)(11) of this section.

(2) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(j) The district director or the director's delegate shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this section. The district director or the director's delegate may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by the director or the director's delegate. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the examiner shall recommend final action by the Commission.

(k) Plugging horizontal drainhole wells. All plugs in horizontal drainhole wells shall be set in accordance with subsection (d)(11) of this section. The productive horizon isolation plug shall be set from a depth 50 feet below the top of the productive horizon to a depth either 50 feet above the top of the productive horizon, or 50 feet above the production casing shoe if the production casing is set above the top of the productive horizon. If the production casing shoe is set below the top of the productive horizon, then the productive horizon isolation plug shall be set from a depth 50 feet below the production casing shoe to a depth that is 50 feet above the top of the productive horizon. In accordance with subsection (d)(7) of this section, the Commission or its delegate may require additional plugs.

Source Note: The provisions of this §3.14 adopted to be effective January 1, 1976; amended to be effective February 29, 1980, 5 TexReg 499; amended to be effective January 1, 1983, 7 TexReg 3989; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective September 8, 1986, 11 TexReg 3792; amended to be effective November 9, 1987, 12 TexReg 3959; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective March 1, 1992, 17 TexReg 1227; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective September 20, 1995, 20 TexReg 6931; amended to be effective September 14, 1998, 23 TexReg 9300; amended to be effective December 28, 1999, 24 TexReg 11711;amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective July 28, 2003, 28 TexReg 5853; amended to be effective December 3, 2003, 28 TexReg 10747; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.15 Surface Equipment Removal Requirements and Inactive Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or until the well has reported production of at least one barrel of oil for oil wells or at least one Mcf of gas for gas wells each month for 12 consecutive months.

(2) Cost calculation for plugging an inactive well--The cost, calculated by the Commission or its delegate, for each foot of well depth plugged based on average actual plugging costs for wells plugged by the Commission for the preceding state fiscal year for the Commission Oil and Gas Division district in which the inactive well is located.

(3) Delinquent inactive well--An inactive well for which, after notice and opportunity for a hearing, the Commission or its delegate has not extended the plugging deadline.

(4) Enhanced oil recovery (EOR) project--A project that does not include a water disposal project and is:

(A) a Commission-approved EOR project that uses any process for the displacement of oil or other hydrocarbons from a reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process;

(B) a certified project described by Texas Tax Code, §202.054; or

(C) any other project approved by the Commission or its delegate for EOR.

(5) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(6) Inactive well--An unplugged well that has been spudded or has been equipped with cemented casing and that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months.

(7) Operator designation form--A certificate of compliance and transportation authority or an application to drill, recomplete, and reenter that has been approved by the Commission or its delegate.

(8) Physical termination of electric service to the well's production site--Disconnection of the electric service to an inactive well site at a point on the electric service lines most distant from the production site toward the main supply line in a manner that will not interfere with electrical supply to adjacent operations, including cathodic protection units.

(b) Plugging of inactive bay and offshore wells required.

(1) An operator of an existing inactive bay or offshore well as defined in §3.78 of this title (relating to Fees and Financial Security Requirements) must:

(A) restore the well to active operation as defined by Commission rule;

(B) plug the well in compliance with a Commission rule or order; or

(C) obtain the approval of the Commission or its delegate of an extension of the deadline for plugging an inactive bay or offshore well.

(2) The Commission or its delegate may not approve an extension of the deadline for plugging an inactive bay or offshore well if the plugging of the well is otherwise required by Commission rules or orders.

(c) Extension of deadline for plugging an inactive bay or offshore well. The Commission or its delegate may administratively grant an extension of the deadline for plugging an inactive bay or offshore well as defined by Commission rules if:

(1) the operator has a current organization report;

(2) the operator has, and on request provides, evidence of a good faith claim to a continuing right to operate the well;

(3) the well and associated facilities are otherwise in compliance with all Commission rules and orders; and

(4) for a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

(d) Plugging of inactive land wells required.

(1) An operator that assumes responsibility for the physical operation and control of an existing inactive land well must maintain the well and all associated facilities in compliance with all applicable Commission rules and orders and within six months after the date the Commission or its delegate approves an operator designation form must either:

(A) restore the well to active operation as defined by Commission rule;

(B) plug the well in compliance with a Commission rule or order; or

(C) obtain approval of the Commission or its delegate of an extension of the deadline for plugging an inactive well.

(2) The Commission or its delegate may not approve an extension of the deadline for plugging an inactive land well if the plugging of the well is otherwise required by Commission rules or orders.

(3) Except for an operator designation form filed for the purpose of a name change, the Commission or its delegate may not approve an operator designation form for an inactive land well until the operator satisfies the requirements of paragraph (1)(C) of this subsection.

(4) If an operator fails to restore the well to active operation as defined by Commission rule, plug the well in compliance with a Commission rule or order, or obtain an extension of the deadline for plugging an inactive well within six months after acquiring an inactive well, the

Commission or its delegate may, after notice and opportunity for hearing, revoke the operator's organization report.

(5) The Commission or its delegate may approve an organization report that is delinquent or has been revoked if the Commission or its delegate simultaneously approves extensions of the deadline for plugging the operator's inactive wells.

(e) Extension of deadline for plugging an inactive land well. The Commission or its delegate may administratively grant an extension of the deadline for plugging an inactive land well if:

(1) the Commission or its delegate approves the operator's Application for an Extension of Deadline for Plugging an Inactive Well (Commission Form W-3X);

(2) the operator has a current organization report;

(3) the operator has, and on request provides evidence of, a good faith claim to a continuing right to operate the well;

(4) the well and associated facilities are otherwise in compliance with all Commission rules and orders; and

(5) for a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

(f) Application for an extension of deadline for plugging an inactive land well.

(1) This subsection does not apply to a bay well or an offshore well as those terms are defined in §3.78 of this title.

(2) An operator must include the following in an application for an extension of the deadline for plugging an inactive well:

(A) an affirmation made by an individual with personal knowledge of the physical condition of the inactive well pursuant to the provisions of Texas Natural Resources Code, §91.143, stating the following: that the operator has physically terminated electric service to the well's production site; and either:

(i) if the operator does not own the surface of the land where the well is located and the well has been inactive for at least five years but for less than 10 years as of the date of renewal of the operator's organization report, that the operator has emptied or purged of production fluids all piping, tanks, vessels, and equipment associated with and exclusive to the well; or

(ii) if the operator does not own the surface of the land where the well is located, and the well has been inactive for at least 10 years as of the date of renewal of the operator's organization report, that the operator has removed all surface equipment and related piping, tanks, tank batteries, pump jacks, headers, fences, and firewalls; has closed all open pits; and has removed all junk and trash, as defined by Commission rule, associated with and exclusive to the well; and

(B) documentation that the operator has satisfied at least one of the following requirements:

(i) for all inactive land wells that an operator has operated for more than 12 months, the operator has plugged or restored to active operation, as defined by Commission rule, 10% of the number of inactive land wells operated at the time of the last annual renewal of the operator's organization report;

(ii) if the operator is a publicly traded entity, for all inactive land wells, the operator has filed with the Commission a copy of the operator's federal documents filed to comply with Financial Accounting Standards Board Statement No. 143, Accounting for Asset Retirement Obligations, and an original executed Uniform Commercial Code Form 1 Financing Statement, filed with the Secretary of State, that names the operator as the "debtor" and the Railroad Commission of Texas as the "secured creditor" and specifies the funds covered by the documents in the amount of the cost calculation for plugging all inactive wells;

(iii) the filing of a blanket bond on Commission Form P-5PB(2), Blanket Performance Bond, a letter of credit on Commission Form P-5LC, Irrevocable Documentary Blanket Letter of Credit, or a cash deposit, in the amount of either the lesser of the cost calculation for plugging all inactive wells or $2 million;

(iv) for each inactive land well identified in the application, the Commission has approved an abeyance of plugging report and the operator has paid the required filing fee;

(v) for each inactive land well identified in the application, the operator has filed a statement that the well is part of a Commission-approved EOR project;

(vi) for each inactive land well identified in the application that is not otherwise required by Commission rule or order to conduct a fluid level or hydraulic pressure test of the well, the operator has conducted a successful fluid level test or hydraulic pressure test of the well and the operator has paid the required filing fee;

(vii) for each inactive land well identified in the application, the operator has filed Commission Form W-3X and the Commission or its delegate has approved a supplemental bond, letter of credit, or cash deposit in an amount at least equal to the cost calculation for plugging an inactive land well for each well specified in the application; or

(viii) for each time an operator files an application for a plugging extension and for each inactive land well identified in the application, the operator has filed Commission Form W-3X and the Commission or its delegate has approved an escrow fund deposit in an amount at least equal to 10% of the total cost calculation for plugging an inactive land well.

(g) Commission action on application for plugging extension.

(1) The Commission or its delegate shall administratively grant all applications for plugging extensions that meet the requirements of Commission rules.

(2) The Commission or its delegate may administratively deny an application for a plugging extension for an inactive well if the Commission or its delegate determines that:

(A) the applicant does not have an active organization report at the time the plugging extension application is filed;

(B) the applicant has not submitted all required filing fees and financial assurance for the requested plugging extension and for renewal of its organization report; or

(C) the applicant has not submitted a signed organization report for the applied-for extension year that qualifies for approval regardless of whether the applicant has complied with the inactive well requirements of this section.

(3) Except as provided in paragraph (2) of this subsection, if the Commission or its delegate determines that an organization report should be denied renewal solely because it does not meet the inactive well requirements of this section, a Commission delegate shall, within a reasonable time of not more than 14 days after receipt of the applicant's administratively complete organization report renewal packet, including all statutorily required fees and financial assurance:

(A) notify the operator of the determination;

(B) provide the operator with a written statement of the reasons for the determination; and

(C) notify the operator that it has 90 days from the expiration of its most recently approved organization report to comply with the requirements of this section.

(4) If, after the expiration of the 90-day period specified in paragraph (3)(C) of this subsection, the Commission or its delegate determines that the operator remains out of compliance with the requirements of this section, the Commission delegate shall mail the operator a written notice of this determination. The operator may request a hearing. If the operator fails to timely file a request for hearing and the required hearing fee, the Commission shall enter an order denying the plugging extension request and denying renewal of the operator's organization report without further notice or opportunity for hearing.

(5) To request a hearing, the operator must file a written request for hearing and the hearing fee of $4,500 with the Hearings Division, no later than 30 days from the date the written notice was mailed to the operator. In the request for hearing, the operator must identify by its assigned American Petroleum Institute (API) number each inactive well for which the operator is seeking a hearing to contest the determination that the well remains out of compliance. At the time an operator files a request for hearing under this subsection, the operator shall provide a list of affected persons to be given notice of the hearing. Affected persons shall include the owners of the surface estate of each tract on which a well that is the subject of the hearing request is located, the director of the Commission's Enforcement Section, and the district director of each Commission district in which the wells are located. The applicant's failure to diligently prosecute a hearing requested under this subsection may result in the application being involuntarily dismissed for want of prosecution on the motion of any affected person or on the Commission's own motion.

(6) If an operator files a timely plugging extension application that is not properly administratively denied for the reasons specified in paragraph (2) of this subsection, then the operator's previously approved organization report shall remain in effect until the Commission approves its plugging extension application or enters a final order denying the application.

(h) Revocation of extension. The Commission or its delegate may revoke an extension of the deadline for plugging an inactive well if the Commission or its delegate determines, after notice and an opportunity for a hearing, that the applicant is ineligible for the extension under the Commission's rules or orders.

(i) Removal of surface equipment for land wells inactive more than 10 years. Requirements to remove surface equipment for land wells inactive more than 10 years do not excuse an operator from compliance with all other applicable Commission rules and orders including the requirements in Chapter 4 of this title (relating to Environmental Protection).

(1) An operator of an inactive land well must leave a clearly visible sign as required by §3.3 of this title (relating to Identification of Properties, Wells, and Tanks) at the wellhead of the well and must maintain wellhead control as required by §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements).

(2) An operator may not store surface equipment removed from an inactive land well on an active lease.

(3) An operator may be eligible for a temporary extension of the deadline for plugging an inactive land well or a temporary exemption from the surface equipment

removal requirements if the operator is unable to comply with the requirements of subsection (f)(2)(A) of this section because of safety concerns or required maintenance of the well site and the operator includes with the application a written affirmation of the facts regarding the safety concerns or maintenance.

(4) An operator may be eligible for an extension of the deadline for plugging a well without complying with the surface equipment removal requirements for inactive land wells if the well is located on a unit or lease or in a field associated with an EOR project and the operator includes a statement in the written affirmation that the well is part of such a project. The exemption provided by this subsection applies only to the equipment associated with current and future operations of the project.

(j) Abeyance of plugging report.

(1) An operator that files an abeyance of plugging report must:

(A) pay an annual fee of $100 for each inactive land well covered by the report;

(B) use Commission Form W-3X on which the operator must specify the field and the covered wells within that field; and

(C) for each well, include a certification signed and sealed by a person licensed by the Texas Board of Professional Engineers or the Texas Board of Professional Geoscientists stating that the well has:

(i) a reasonable expectation of economic value in excess of the cost of plugging the well for the duration of the period covered by the report, based on the cost calculation for plugging an inactive well;

(ii) a reasonable expectation of being restored to a beneficial use that will prevent waste of oil or gas resources that otherwise would not be produced if the well were plugged; and

(iii) documentation demonstrating the basis for the affirmation of the well's future utility.

(2) Except as provided in paragraph (3) of this subsection, the Commission or its delegate may not transfer an abeyance of plugging report to a new operator of an existing inactive land well. The new operator of an existing inactive land well must file a new abeyance of plugging report or otherwise comply with the requirements of this subchapter not later than six months after the date the Commission or its delegate approves the new operator's request to be recognized as the operator of the well.

(3) The Commission or its delegate may transfer an abeyance of plugging report in the event of a change of name of an operator.

As in effect on 12/20/2021.

(k) Enhanced oil recovery (EOR) project.

(1) An inactive well is considered to be part of an EOR project if the well is located on a unit or lease or in a field associated with a Commission-approved EOR project.

(2) Except as provided in paragraph (3) of this subsection, the Commission and its delegate may not transfer a statement that an inactive well is part of an EOR project to a new operator of an existing inactive well. A new operator of an existing inactive well must file a new statement stating that the well is part of such an EOR project or otherwise comply with the provisions of this section not later than six months after the date the Commission or its delegate approves the new operator's request to be recognized as the operator of the well.

(3) The Commission or its delegate may transfer a statement that a well is part of an EOR project in the event of a change of name of an operator.

(l) Fluid level or hydraulic pressure test for inactive wells more than 25 years old.

(1) At least three days prior to the test, the operator must give the district office notice of the date and approximate time the operator intends to conduct a fluid level or hydraulic pressure test. The district office may require that a test be witnessed by a Commission employee. The district office may allow an operator to conduct a test even if notice of the test is provided to the district office fewer than three days prior to the test.

(2) No operator may conduct a test other than a fluid level or hydraulic pressure test without prior approval from the district director or the director's delegate.

(3) For each inactive well that is more than 25 years old and that has been inactive more than 10 years, the operator must perform either a fluid level test once every 12 months or a hydraulic pressure test once every five years and obtain the approval of the Commission or its delegate of the results of said tests.

(4) Notwithstanding the provisions of paragraph (1) of this subsection, an operator may conduct a hydraulic pressure test without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice of the date and approximate time for the test at least three days prior to the time the test will be conducted; the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata or 100 feet below the top of cement behind the production casing, whichever is deeper; and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(5) Using Commission Form H-15, each operator must file in the Commission's Austin office the results of a successful fluid level test within 30 days of the date the test was performed. The results, if approved, are valid for a period of one year from the date of the test. Upon request by the Commission or its delegate, the operator must file

the actual test data.

(6) Using Commission Form H-5 or Form H-15, each operator must file in the district office the results of a successful hydraulic pressure test, including the original pressure recording chart or its electronic equivalent, within 30 days of the date the test was performed. The results, if approved, are valid for a period of five years from the date of the test, unless the Commission or its delegate requires the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources.

(7) An operator of an inactive well that is more than 25 years old may not return that inactive well to active operation unless the operator performs either a successful fluid level test of the well within 12 months prior to the return to activity or a successful hydraulic pressure test of the well within five years prior to the return to activity.

(m) Fluid level or hydraulic pressure test for inactive land well less than 25 years old.

(1) At least three days prior to the test, each operator must give the district office notice of the date and approximate time the operator intends to conduct a fluid level or hydraulic pressure test. The district office may require that a test be witnessed by a Commission employee. The district office may allow an operator to conduct a test even if notice of the test is provided to the district office fewer than three days prior to the test.

(2) No operator may conduct a test other than a fluid level or hydraulic pressure test without prior approval from the district director or the director's delegate.

(3) Notwithstanding the provisions of paragraph (1) of this subsection, an operator may conduct a hydraulic pressure test without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice of the date and approximate time for the test at least three days prior to the time the test will be conducted; the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata or 100 feet below the top of cement behind the production casing, whichever is deeper; and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(4) An operator that files documentation of a fluid level test or a hydraulic pressure test for an inactive land well less than 25 years old in order to obtain a plugging extension must pay an annual fee of $50 for each well covered by the documentation.

(5) Using Commission Form H-15, each operator must file in the Commission's Austin office the results of a successful fluid level test within 30 days of the date the test was performed. The results, if approved, are valid for a period of one year from the date of the test. Upon request by the Commission or its delegate, the operator must file the actual test data.

(6) Using Commission Form H-5 or Form H-15, each operator must file in the district office the results of a successful hydraulic pressure test, including the original pressure recording chart or its electronic equivalent, within 30 days of the date the test was performed. The results, if approved, are valid for a period of five years from the date of the test, unless the Commission or its delegate requires the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources.

(7) The Commission or its delegate may transfer documentation of the results of a fluid level or hydraulic pressure test to a new operator of an existing inactive land well that is less than 25 years old.

(n) Supplemental financial assurance.

(1) A supplemental bond, letter of credit, or cash deposit filed as part of an application for an extension for an inactive land well is in addition to any other financial assurance otherwise required of the operator or for the well.

(2) The Commission or its delegate may not transfer a supplemental bond, letter of credit, or cash deposit to a new operator of an existing inactive land well. A new operator of an existing inactive land well must file a new supplemental bond, letter of credit, or cash deposit or otherwise comply with the provisions of this section not later than six months after the date the Commission or its delegate approves an operator designation form.

(o) Escrow funds.

(1) An operator must deposit escrow funds with the Commission each time the operator files an application for an extension of the deadline for plugging an inactive well.

(2) The Commission or its delegate may release escrow funds deposited with the Commission only as prescribed by §3.78 of this title.

(p) Plugging more than 10% of inactive well inventory. If an operator plugs more than 10% of the number of inactive land wells during a 12-month organization report cycle, the Commission will count the number of plugged wells above 10% toward fulfillment of the 10% blanket option under subsection (f)(2)(B)(i) of this section during the next organization report cycle.

Source Note: The provisions of this §3.15 adopted to be effective September 13, 2010, 35 TexReg 8332; amended to be effective August 15, 2011, 36 TexReg 5096; amended to be effective July 2, 2012, 37 TexReg 4894; amended to be effective January 1, 2017, 41 TexReg 9465.

§3.16 Log and Completion or Plugging Report

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Electric log--A density, sonic, or resistivity (except dip meter) log run over the entire wellbore.

(2) Drilling operation--A continuous effort to drill or deepen a wellbore for which the commission has issued a permit.

(3) Operator--A person who assumes responsibility for the regulatory compliance of a well as shown by a form the person files with the commission and the commission approves.

(4) Well--A well drilled for any purpose related to exploration for or production or storage of oil or gas or geothermal resources, including a well drilled for injection of fluids to enhance hydrocarbon recovery, disposal of produced fluids, disposal of waste from exploration or production activity, or brine mining.

(b) Completion and plugging reports.

(1) The operator of a well shall file with the commission the appropriate completion report within 90 days after completion of the well or within 150 days after the date on which the drilling operation is completed, whichever is earlier.

(2) The operator of a well shall file with the Commission an amended completion report within 30 days of any physical changes made to the well, such as any change in perforations, or openhole or casing records.

(3) If the well is a dry hole, the operator shall file with the commission an appropriate plugging report within 30 days after the well is plugged.

(c) Electric logs. Except as otherwise provided in this section, not later than the 90th day after the date a drilling operation is completed, the operator shall file with the commission a legible and unaltered copy of an electric log, except that where a well is deepened, a legible and unaltered copy of an electric log shall be filed if such log is run over a deeper interval than the interval covered by an electric log for the well already on file with the commission. In the event an electric log, as defined in this section, has not been run, subject to the commission's approval, the operator shall file a lithology log or gamma ray log of the entire wellbore. In the event no log has been run over the entire wellbore, subject to the commission's approval, the operator shall file the log which is the most nearly complete of the logs run. An electric log shall be filed with the commission electronically in a digital format acceptable to the commission, when the commission has the technological capability to receive the electronic filing. Nothing in this subsection requires an operator to run an electric log in conjunction with the drilling or deepening of a well.

(d) Delayed filing based on confidentiality. Each log filed with the commission shall be considered public information and shall be available to the public during normal business hours. If the operator of a well desires a log to be confidential, on or before the 90th day after the date a drilling operation is completed, the operator must submit to the Oil and Gas Division in Austin a written request for a delayed filing of the log. If a well is drilled on land submerged in state water, when filing such a request, the operator must retain the log and may delay filing such log for five years beginning from the date the drilling operation was completed. For any other well, the operator must retain the log and may delay filing such log for three years beginning from the date the drilling operation was completed. Logs must be filed with the commission within 30 days after the expiration of the confidentiality period.

(e) Sanctions. If an operator fails to file a completion report or log in accordance with the provisions of this section, the commission may refuse to assign an allowable to a well, set the allowable for such well at zero, and/or initiate penalty action pursuant to the Texas Natural Resources Code, Title 3.

Source Note: The provisions of this §3.16 adopted to be effective January 1, 1976; amended to be effective February 20, 1986, 11 TexReg 545; amended to be effective January 30, 2006, 31 TexReg 477; amended to be effective April 28, 2015, 40 TexReg 2273; amended to be effective February 23, 2016, 41 TexReg 1226.

§3.17 Pressure on Bradenhead

(a) All wells shall be equipped with a Bradenhead. Whenever pressure develops between any two strings of casing, the district office shall be notified immediately. No cement may be pumped between any two strings or pipe at the top of the hole, except after permission has been granted by the district office.

(b) Any well showing pressure on the Bradenhead, or leaking gas, oil, or geothermal resource between the surface and the production or oil string shall be tested in the following manner. The well shall be killed and pump pressure applied through the tubing head. Should the pressure gauge on the Bradenhead reflect the applied pressure, the casing shall be condemned and a new production or oil string shall be run and cemented. This method shall be used when the origin of the pressure cannot be determined otherwise.

Source Note: The provisions of this §3.17 adopted to be effective January 1, 1976.

§3.18 Mud Circulation Required

When coming out of the hole with the drill pipe, drilling fluid shall be circulated until equalized, and a fill-up line shall be turned into the casing to insure a full load of fluid on the bottom of the hole at all times.

Source Note: The provisions of this §3.18 adopted to be effective January 1, 1976.

§3.19 Density of Mud-Fluid

In cable tool drilling, no operator shall drill into a known oil, gas, or geothermal resource producing formation with water from a higher formation in the hole, or with a sufficient head of water introduced into the hole to prevent gas blowing to the surface. The well shall either be allowed to blow until it has been drilled-in or it shall be drilled under a head of fluid whose weight shall average not less than 9 1/2 pounds per gallon; but in no case shall gas be allowed to blow for a longer period than three days after completion of the well. Mud-laden fluid used for protecting oil, gas, or geothermal resource bearing sands in upper formations while oil, gas, or geothermal resource is being produced from deeper formations shall have an average weight of not less than 91 pounds per gallon.

Source Note: The provisions of this §3.19 adopted to be effective January 1, 1976.

§3.20 Notification of Fire Breaks, Leaks, or Blow-outs

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.
As in effect on 12/20/2021.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

§3.21 Fire Prevention and Swabbing

(a) No hydrocarbon flow tank, unless entirely buried, shall hereafter be placed nearer than 150 feet from any derrick, rig, building, power plant, or boiler of any description. The director of the Oil and Gas Division or his delegate may administratively grant exceptions to this requirement. If the director of the Oil and Gas Division declines to administratively grant, continue, or extend an exception, the operator shall move the hydrocarbon flow tank to the required distance or request a hearing on the matter. After hearing, the examiner shall recommend final action to the commission.

(b) No field working hydrocarbon tank having a capacity of 10,000 barrels or more shall be built nearer than 200 feet (measured from shell to shell) to any other like tank.

(c) No person engaged in the production, transportation, storage, handling, refining, reclaiming, processing, treating, or marketing of crude petroleum oil or the products or by-products thereof shall store, either permanently or temporarily, crude petroleum oil or the products and by-products thereof in open pits or earthen storage.

(d) All oil tanks where there is a gas hazard shall be gas tight and provided with proper gas vents.

(e) No forge or open light shall be placed inside the derrick of a well showing oil or gas.

(f) Boilers must be equipped with steam lines for fighting fire and must not be set nearer than 150 feet to any producing well.

(g) All wells shall be cleaned into a pit not less than 40 feet from the derrick floor and 150 feet from any fire hazard.

(h) No boiler or electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank.

(i) Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of any well, tank, or pump station. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

(j) Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks, that are within the corporate limits of any city, town, or village; or where such tanks are closer than 500 feet to any highway or inhabited dwelling or closer than 1,000 feet to any school or church; or where such tanks are so located as to be deemed by the commission to be an objectionable hazard.

(k) Swabbing, bailing, or air jetting of wells is prohibited as a production method for wells unless the Commission has, after notice and hearing, granted an exception to this subsection. The Commission shall give notice of the hearing at least 10 days prior to the date of the hearing.

(1) An operator seeking an exception to allow swabbing, bailing, or air jetting of a well shall:

(A) provide the Commission with the names and mailing addresses of the mineral interest owners of record and surface owners of record of the lease on which a well for which an exception is sought is located;

(B) present evidence at the hearing establishing:

(i) the method of production proposed;

(ii) that any production is properly accounted for pursuant to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil);

(iii) that the proposed exception is necessary to prevent waste or protect correlative rights;

(iv) that wellhead control is sufficient to prevent releases from the well;

(v) that no pollution of usable quality water or safety hazard will result from either the proposed production method or the condition of the well; and

(vi) that the operator possesses a continuing good faith claim to the right to operate the well.

(2) In addition to the information set out in paragraph (1) of this subsection, factors that the Commission may consider in ruling on a request for an exception include:

(A) whether the well has passed a mechanical integrity test within the preceding 12 months;

(B) the estimated monthly and cumulative production from the well if the requested exception is granted;

(C) whether production will be into an on-lease tank battery or a mobile tank;

(D) the adequacy of the financial assurance provided by the operator to assure that the well will be timely and properly plugged;

(E) whether production volume, fine sands in the reservoir, or other factors render pumping of the well impracticable;

(F) whether the reservoir from which the well produces contains hydrogen sulfide; and

(G) the operator's history of compliance with Commission rules.

(3) This section does not prohibit swabbing as a non-recurring method to start initial production, to test or clean out a well, or to restore a well to flowing or pumping status.

(l) Operation and maintenance of electrical power lines. An operator must construct, operate, and maintain an electrical power line serving a well site or other surface facility employed in operations incident to oil and gas development and production in accordance with the National Electrical Code published by the National Fire Protection Association and adopted by the Texas Department of Licensing and Regulation in §73.100 of this title (relating to Technical Requirements).

Source Note: The provisions of this §3.21 adopted to be effective January 1, 1976, amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective October 2, 2002, 27 TexReg 9149; amended to be effective September 13, 2010, 35 TexReg 8332.

§3.22 Protection of Birds

(a) If an operator who maintains a tank or pit does not take protective measures necessary to prevent harm to birds, the operator may incur liability under federal and state wildlife protection laws. Federal statutes, such as the Migratory Bird Treaty Act, provide substantial penalties for the death of certain species of birds due to contact with oil in a tank or pit. These penalties may include imprisonment. State statutes also protect certain species of birds. The Railroad Commission of Texas (commission) is cooperating with federal and state wildlife authorities in their efforts to protect birds.

(b) An operator must screen, net, cover, or otherwise render harmless to birds the following categories of open-top tanks and pits associated with the exploration, development, and production of oil and gas, including transportation of oil and gas by pipeline:

(1) open-top storage tanks that are eight feet or greater in diameter and contain a continuous or frequent surface film or accumulation of oil; however, temporary, portable storage tanks that are used to hold fluids during drilling operations, workovers, or well tests are exempt;

(2) skimming pits as defined in §3.8 of this title (relating to Water Protection) (Statewide Rule 8); and

(3) collecting pits as defined in §3.8 of this title (relating to Water Protection) that are used as skimming pits.

(c) If the commission finds a surface film or accumulation of oil in any other pit regulated under §3.8 of this title (relating to Water Protection), the commission will instruct the operator to remove the oil. If the operator fails to remove the oil from the pit in accordance with the commission's instructions or if the commission finds a surface film or accumulation of oil in the pit again within a 12-month period, the commission will require the operator to screen, net, cover, or otherwise render the pit harmless to birds. Before complying with this requirement, the operator will have a right to a hearing upon request. In addition to the enforcement actions specified by this subsection, the commission may take any other appropriate enforcement actions within its authority.

Source Note: The provisions of this §3.22 adopted to be effective September 1, 1991, 16 TexReg 2523; amended to be effective November 1, 1991, 16 TexReg 4737.

§3.23 Vacuum Pumps

The installation of a vacuum pump or other device for the purpose of putting vacuum on any gas or oil-bearing formation, or the application of any vacuum to any gas or oil-bearing formation is prohibited, except as follows.

(1) If casinghead gas is utilized in a casinghead-gas plant, vacuum may be used, but no more than is sufficient to gather the gas and deliver it at the plant. In no event shall more than two points of vacuum (two inches of mercury) be used at the casinghead.

(2) In a field which is depleted or practically depleted vacuum may be used, but no vacuum pump shall be installed or used without a permit from the commission obtained upon application after notice to adjacent lease owners and operators and a public hearing on such

application.

Source Note: The provisions of this §3.23 adopted to be effective January 1, 1976.

§3.24 Check Valves Required

(a) Where two or more wells are being produced through a common line, a common separator, or a common manifold, the flow lines leading from each well to such common line, common separator, or common manifold shall be equipped with a check valve or other means of shut-off which shall at all times be kept in good working order. The check valve or other means of shut-off shall be placed in each flow line above the surface of the ground and shall be located in the flow line as close to the wellhead connection as is practicable. Where a manifold system is employed in which each well produced through the manifold system has its own individual flow line leading from the wellhead to the manifold, then it shall be permissible for the check valve or other means of shut-off to be placed in the flow line near a point where the flow line enters the manifold system. The check valve or other means of shut-off must be above ground, and must be in the flow line serving the well and must be located between the wellhead and the point where the flow line connects with any other flow line, common separator, or common manifold. Each check valve or other means of shut-off shall be placed in the flow line serving the well so that it will permit the passage of fluids from the well and will act as a check to prevent any fluid from entering the well through the flow line from any outside source.

(b) Operator shall do all things necessary to keep the check valve or other means of shut-off in good working order, and operators, when requested by an agent of the commission, will test the check valve or other means of shut-off for leakage.

Source Note: The provisions of this §3.24 adopted to be effective January 1, 1976.

§3.25 Use of Common Storage

(a) Where oil and/or other liquid hydrocarbons are produced from two or more separate reservoirs or zones and separate proration schedules are published by the Commission for each reservoir or zone, the use of common storage is authorized as long as the requirements of §3.26 and §3.27 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil, and Gas to be Measured and Surface Commingling of Gas, respectively) are met. An operator utilizing common storage pursuant to this section shall not be required to file a separate Form P-4, Certificate of Compliance and Transportation Authority, for each reservoir or zone, but may file one form to authorize the transportation of oil or gas from all reservoirs or zones producing into common storage.

(b) A gatherer transporting oil from such common storage shall not be required to file a separate transporter's report for each separate reservoir or zone or each separate

(5) when the well is completed in a regulatory field where the allocation formula is based in whole or in part on the downhole pressure of the well, and that allocation formula is not suspended;

(6) when necessary to reinstate an allowable; or

(7) when required by Commission order, special field rule, or other Commission rule.

(f) If the deliverability of a well changes after a test is reported to the Commission, the deliverability of record for a well will be decreased upon receipt of a written request from the operator to reduce the deliverability of record to a specified amount. If the deliverability of a well increases, a retest must be conducted in the manner specified in this section and must be reported on Form G-10 before the deliverability of record will be increased.

(g) First purchasers with packages of gas dedicated entirely to a downstream purchaser shall coordinate testing with and provide test results to that downstream purchaser if requested by the downstream purchaser. In these cases, the downstream purchaser upon request to the operator shall have the right to witness all deliverability tests and retests.

(h) Tests of wells connected to a pipeline shall be made in a manner that no gas is flared, vented, or otherwise wastefully used.

Source Note: The provisions of this §3.28 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective October 12, 1998, 23 TexReg 10397; amended to be effective February 28, 2000, 25 TexReg 1592; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 1, 2017, 41 TexReg 9470.

§3.29 Hydraulic Fracturing Chemical Disclosure Requirements

(a) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Accredited laboratory--A laboratory as defined in Texas Water Code, §5.801.

(2) Additive--Any chemical substance or combination of substances, including a proppant, contained in a hydraulic fracturing fluid that is intentionally added to a base fluid for a specific purpose whether or not the purpose of any such substance or combination of substances is to create fractures in a formation.

(3) Adjacent property--A tract of property next to the tract of property on which the subject wellhead is located, including a tract that meets only at a corner point.

(4) API number--A unique, permanent, numeric identifier assigned to each well drilled for oil or gas in the United States.

(5) Base fluid--The continuous phase fluid type, such as water, used in a particular hydraulic fracturing treatment.

(6) Chemical Abstracts Service--The division of the American Chemical Society that is the globally recognized authority for information on chemical substances.

(7) Chemical Abstracts Service number or CAS number--The unique identification number assigned to a chemical by the Chemical Abstracts Service.

(8) Chemical Disclosure Registry--The chemical registry website known as FracFocus developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

(9) Chemical family--A group of chemical ingredients that share similar chemical properties and have a common general name.

(10) Chemical ingredient--A discrete chemical constituent with its own specific name or identity, such as a CAS number, that is contained in an additive.

(11) Commission--The Railroad Commission of Texas.

(12) Delegate--The person authorized by the director to take action on behalf of the Railroad Commission of Texas under this section.

(13) Director--The director of the Oil and Gas Division of the Railroad Commission of Texas or the director's delegate.

(14) Health professional or emergency responder--A physician, physician's assistant, industrial hygienist, toxicologist, epidemiologist, nurse, nurse practitioner, or emergency responder who needs information in order to provide medical or other health services to a person exposed to a chemical ingredient.

(15) Hydraulic fracturing fluid--The fluid, including the applicable base fluid and all additives, used to perform a particular hydraulic fracturing treatment.

(16) Hydraulic fracturing treatment--The treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas.

(17) Landowner--The person listed on the applicable county appraisal roll as owning the real property on which the relevant wellhead is located.

(18) Operator--An operator as defined in Texas Natural Resources Code, Chapter 89.

(19) Person--Natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(20) Proppant--Sand or any natural or man-made material that is used in a hydraulic fracturing treatment to prop open the artificially created or enhanced fractures once the treatment is completed.

(21) Requestor--A person who is eligible to request information claimed to be entitled to trade secret protection in accordance with Texas Natural Resources Code, §91.851(a)(5).

(22) Service company--A person that performs hydraulic fracturing treatments on a well in this state.

(23) Supplier--A company that sells or provides an additive for use in a hydraulic fracturing treatment.

(24) Total water volume--The total amount of water in gallons used as the carrier fluid for the hydraulic fracturing job. It may include recycled water and newly acquired water.

(25) Trade name--The name given to an additive or a hydraulic fracturing fluid system under which that additive or hydraulic fracturing fluid system is sold or marketed.

(26) Trade secret--Any formula, pattern, device, or compilation of information that is used in a person's business, and that gives the person an opportunity to obtain an advantage over competitors who do not know or use it. The six factors considered in determining whether information qualifies as a trade secret, in accordance with the definition of "trade secret" in the Restatement of Torts, Comment B to Section 757 (1939), as adopted by the Texas Supreme Court in *Hyde Corp. v. Huffines*, 314 S.W.2d 763, 776 (Tex. 1958), include:

(A) the extent to which the information is known outside of the company;

(B) the extent to which it is known by employees and others involved in the company's business;

(C) the extent of measures taken by the company to guard the secrecy of the information;

(D) the value of the information to the company and its competitors;

(E) the amount of effort or money expended by the company in developing the information; and

(F) the ease or difficulty with which the information could be properly acquired or duplicated by others.

(27) Well--A well as defined in Texas Natural Resources Code, Chapter 89.

(28) Well completion report--The report an operator is required to file with the Commission following the completion or recompletion of a well, if applicable, in accordance with §3.16(b) of this title (relating to Log and Completion or Plugging Report.)

(b) Applicability. This section applies to a hydraulic fracturing treatment performed on a well in the State of Texas for which the Commission has issued an initial drilling permit on or after February 1, 2012.

(c) Required disclosures.

(1) Supplier and service company disclosures.

(A) As soon as possible, but not later than 15 days following the completion of hydraulic fracturing treatment(s) on a well, the supplier or the service company must provide to the operator of the well the following information concerning each chemical ingredient intentionally added to the hydraulic fracturing fluid:

(i) each additive used in the hydraulic fracturing fluid and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment;

(ii) each chemical ingredient subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2);

(iii) all other chemical ingredients not submitted under subparagraph (A) of this paragraph that were intentionally included in, and used for the purpose of creating, hydraulic fracturing treatment(s) for the well;

(iv) the actual or maximum concentration of each chemical ingredient listed under clause (i) or clause (ii) of this subparagraph in percent by mass; and

(v) the CAS number for each chemical ingredient, if applicable.

(B) The supplier or service company must provide the operator of the well a written statement that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) of the operator's well is claimed to be entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552. If the chemical ingredient name and/or CAS number is claimed as trade secret information, the supplier or service company making the claim must provide:

(i) the supplier's or service company's contact information, including the name, authorized representative, mailing address, and telephone number; and

(ii) the chemical family, unless providing the chemical family would disclose information protected as a trade secret.

(2) Operator disclosures.

(A) On or before the date the well completion report for a well on which hydraulic fracturing treatment(s) was/were conducted is submitted to the Commission in accordance with §3.16(b) of this title, the operator of the well must complete the Chemical Disclosure Registry form and upload the form on the Chemical Disclosure Registry, including:

(i) the operator name;

(ii) the date of completion of the hydraulic fracturing treatment(s);

(iii) the county in which the well is located;

(iv) the API number for the well;

(v) the well name and number;

(vi) the longitude and latitude of the wellhead;

(vii) the total vertical depth of the well;

(viii) the total volume of water used in the hydraulic fracturing treatment(s) of the well or the type and total volume of the base fluid used in the hydraulic fracturing treatment(s), if something other than water;

(ix) each additive used in the hydraulic fracturing treatments and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment(s);

(x) each chemical ingredient used in the hydraulic fracturing treatment(s) of the well that is subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), as provided by the chemical supplier or service company or by the operator, if the operator provides its own chemical ingredients;

(xi) the actual or maximum concentration of each chemical ingredient listed under clause (x) of this subparagraph in percent by mass;

(xii) the CAS number for each chemical ingredient listed, if applicable; and

(xiii) a supplemental list of all chemicals and their respective CAS numbers, not subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), that were intentionally included in and used for the purpose of creating the hydraulic fracturing treatments for the well.

(B) If the Chemical Disclosure Registry known as FracFocus is temporarily inoperable, the operator of a well on which hydraulic fracturing treatment(s) were performed must supply the Commission with the required information with the well completion report and must upload the information on the FracFocus Internet website when the website is again operable. If the Chemical Registry known as FracFocus is discontinued or becomes permanently inoperable, the information required by this rule must be filed as an attachment to the completion report for the well, which is posted, along with all attachments, on the Commission's Internet website, until the Commission amends this rule to specify another publicly accessible Internet website.

(C) If the supplier, service company, or operator claim that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) is entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552, the operator of the well must indicate on the Chemical Disclosure Registry form or the supplemental list that the additive or chemical ingredient is claimed to be entitled to trade secret protection. If a chemical ingredient name and/or CAS number is claimed to be entitled to trade secret protection, the chemical family or other similar description associated with such chemical ingredient must be provided. The operator of the well on which the hydraulic fracturing treatment(s) were performed must provide the contact information, including the name, authorized representative, mailing address, and phone number of the business organization claiming entitlement to trade secret protection.

(D) Unless the information is entitled to protection as a trade secret under Texas Government Code, Chapter 552, information submitted to the Commission or uploaded on the Chemical Disclosure Registry is public information.

(3) Inaccuracies in information. A supplier is not responsible for any inaccuracy in information that is provided to the supplier by a third party manufacturer of the additives. A service company is not responsible for any inaccuracy in information that is provided to the service company by the supplier. An operator is not responsible for any inaccuracy in information provided to the operator by the supplier or service company.

(4) Disclosure to health professionals and emergency responders. A supplier, service company or operator may not withhold information related to chemical ingredients used in a hydraulic fracturing treatment, including information identified as a trade secret, from any health professional or emergency responder who needs the information for diagnostic, treatment or other emergency response purposes subject to procedures set forth in 29 Code of Federal Regulations §1910.1200(i). A supplier, service company or operator must provide directly to a health professional or emergency responder, all information in the person's possession that is required by the health professional or emergency responder, whether or not the information may qualify for trade secret protection under subsection (e) of this section. The person disclosing information to a health professional or emergency responder must include with the disclosure, as soon as circumstances permit, a statement of the health professional's confidentiality obligation. In an emergency situation, the supplier, service company or operator must provide the information immediately upon request to the

person who determines that the information is necessary for emergency response or treatment. The disclosures required by this subsection must be made in accordance with the procedures in 29 Code of Federal Regulations §1910.1200(i) with respect to a written statement of need and confidentiality agreements, as applicable.

(d) Disclosures not required. A supplier, service company, or operator is not required to:

(1) disclose ingredients that are not disclosed to it by the manufacturer, supplier, or service company;

(2) disclose ingredients that were not intentionally added to the hydraulic fracturing treatment;

(3) disclose ingredients that occur incidentally or are otherwise unintentionally present which may be present in trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid; or

(4) identify specific chemical ingredients and/or their CAS numbers that are claimed as entitled to trade secret protection based on the additive in which they are found or provide the concentration of such ingredients, unless the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission.

(e) Trade secret protection.

(1) A supplier, service company, or operator is not required to disclose trade secret information, unless the Office of the Attorney General or a court of proper jurisdiction determines that the information is not entitled to trade secret protection under Texas Government Code, Chapter 552.

(2) If the specific identity and/or CAS number of a chemical ingredient, the concentration of a chemical ingredient, or both the specific identity and/or CAS number and concentration of a chemical ingredient are claimed or have been finally determined to be entitled to protection as a trade secret under Texas Government Code, Chapter 552, the supplier, service company, or operator, as applicable, may withhold the specific identity and/or CAS number, the concentration, or both the specific identity and/or CAS number and concentration, of the chemical ingredient from the information provided to the operator. If the supplier, service company, or operator, as applicable, elects to withhold that information, the supplier, service company, or operator, as applicable, must provide to the operator or the Commission, as applicable, information that:

(A) indicates that the specific identity and/or CAS number of the chemical ingredient, the concentration of the chemical ingredient, or both the specific identity and/or CAS number and concentration of the chemical ingredient are entitled to protection as trade secret information; and

(B) discloses the chemical family associated with the chemical ingredient; or

(C) discloses the properties and effects of the chemical ingredient(s), the identity of which is withheld.

(f) Trade secret challenge.

(1) The following persons may submit a request challenging a claim of entitlement to trade secret protection for any chemical ingredients and/or CAS numbers used in the hydraulic fracturing treatment(s) of a well:

(A) the landowner on whose property the relevant wellhead is located;

(B) the landowner who owns real property adjacent to property described in subparagraph (A) of this paragraph; or

(C) a department or agency of this state with jurisdiction over a matter to which the claimed trade secret information is relevant.

(2) A requestor must certify in writing to the director, over the requestor's signature, to the following:

(A) the requestor's name, address, and daytime phone number;

(B) if the requestor is a landowner, a statement that the requestor is listed on the county appraisal roll as owning the property on which the relevant wellhead is located or is listed on the county appraisal roll as owning property adjacent to the property on which the relevant wellhead is located;

(C) the county in which the wellhead is located; and

(D) the API number or other Railroad Commission of Texas identifying information, such as field name, oil lease name and number, gas identification number, and well number.

(3) A requestor may use the following format to provide the written certification required by paragraph (2) of this subsection:

REQUEST TO CHALLENGE CLAIM OF ENTITLEMENT
TO TRADE SECRET PROTECTION OF HYDRAULIC FRACTURING
TREATMENT CHEMICAL COMPOSITION

I, _______(name)_________, challenge the claim of entitlement to trade secret protection for portions of the chemicals or other substances used in the hydraulic fracturing treatment of the following well:

Operator name: ______________________________
County name: ______________________________
API number: ______________________________
Field Name: ______________________________
Railroad Commission oil lease name and number: ______________
Railroad Commission gas identification number: ______________
Well Number: ______________________________

The following is to be completed if the requestor is a landowner:

I certify that I am listed on the appraisal roll as owning the property on which the relevant wellhead is located or I am listed on the appraisal roll as owning property adjacent to the property on which the relevant wellhead is located.

Name of requestor: ______________________________
Mailing address of Requestor:
____

____
Phone number of requestor: ______________________________
Email address of requestor (optional):
____

EMAIL ADDRESS: YOU ARE NOT REQUIRED TO PROVIDE AN EMAIL ADDRESS when completing and filing this form. Please be aware that information provided to any governmental body may be subject to disclosure pursuant to the Texas Public Information Act or other applicable federal or state legislation. IF YOU PROVIDE AN EMAIL ADDRESS, YOU AFFIRMATIVELY CONSENT TO THE RELEASE OF THAT EMAIL ADDRESS TO THIRD PARTIES. Other departments within the Railroad Commission also may use the email address you provide to communicate with you.

Signature of Requestor: ______________________________

Date: ______________________

As in effect on 12/20/2021.

(4) A requestor must file a request no later than 24 months from the date the operator filed the well completion report for the well on which the hydraulic fracturing treatment(s) were performed. A landowner who owned the property on which the wellhead is located, or owned adjacent property, on or after the date the operator filed with the Commission the completion report for the subject well may challenge a claim of entitlement to trade secret protection within that 24-month period only. The Commission will determine whether or not the request has been received within the allowed 24-month period.

(5) If the Commission determines that the request has been received within the allowed 24-month period and the certification is properly completed and signed, the Commission will consider this sufficient for the purpose of forwarding the request to the Office of the Attorney General.

(6) Within 10 business days of receiving a request that complies with paragraph (2) of this subsection, the director must:

(A) submit to Office of the Attorney General, Open Records Division, a request for decision regarding the challenge;

(B) notify the operator of the subject well and the owner of the claimed trade secret information of the submission of the request to the Office of the Attorney General and of the requirement that the owner of the claimed trade secret information submit directly to the Office of Attorney General, Open Records Division, the claimed trade secret information, clearly marked "confidential," submitted under seal; and

(C) inform the owner of the claimed trade secret information of the opportunity to substantiate to the Office of the Attorney General, Open Records Division, its claim of entitlement of trade secret protection, in accordance with Texas Government Code, Chapter 552.

(7) If the Office of the Attorney General determines that the claim of entitlement to trade secret protection is valid under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information shall not be required to disclose the trade secret information, subject to appeal.

(8) The request shall be deemed withdrawn if, prior to the determination of the Office of the Attorney General on the validity of the trade secret claim, the owner of the claimed trade secret information provides confirmation to the Commission and the Office of the Attorney General that the owner of the claimed trade secret information has voluntarily provided the information that is the subject of the request to the requestor subject to a claim of trade secret protection, or the requestor submits to the Commission and the Office of the Attorney General a written notice withdrawing the request.

As in effect on 12/20/2021.

(9) A final determination by the Office of the Attorney General regarding the challenge to the claim of entitlement of trade secret protection of any withheld information may be appealed within 10 business days to a district court of Travis County pursuant to Texas Government Code, Chapter 552.

(10) If the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the withheld information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information must disclose such information to the requestor as directed by the Office of the Attorney General or a court of proper jurisdiction on appeal.

(g) Trade secret confidentiality. A health professional or emergency responder to whom information is disclosed under subsection (c)(4) of this section must hold the information confidential, except that the health professional or emergency responder may, for diagnostic or treatment purposes, disclose information provided under that subsection to another health professional, emergency responder, or accredited laboratory. A health professional, emergency responder, or accredited laboratory to which information is disclosed by another health professional or emergency responder under this subsection must hold the information confidential and the disclosing health professional or emergency responder must include with the disclosure, or in a medical emergency, as soon as circumstances permit, a statement of the recipient's confidentiality obligation pursuant to this subsection.

(h) Penalties. A violation of this section may subject a person to any penalty or remedy specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the Commission. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) (Rule 73) for violation of this section.

Source Note: The provisions of this §3.29 adopted to be effective January 2, 2012, 36 TexReg 9307.

§3.30 Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)

(a) Need for agreement. Several statutes cover persons and activities where the respective jurisdictions of the RRC and the TCEQ may intersect. This rule is a statement of how the agencies implement the division of jurisdiction.

(1) Section 10 of House Bill 1407, 67th Legislature, 1981, which appeared as a footnote to the Texas Solid Waste Disposal Act, Texas Civil Statutes, Article 4477-7, provides as follows: On or before January 1, 1982, the

Texas Department of Water Resources, the Texas Department of Health, and the Railroad Commission of Texas shall execute a memorandum of understanding that specifies in detail these agencies' interpretation of the division of jurisdiction among the agencies over waste materials that result from or are related to activities associated with the exploration for and the development, production, and refining of oil or gas. The agencies shall amend the memorandum of understanding at any time that the agencies find it to be necessary.

(2) Texas Health and Safety Code, §401.414, relating to Memoranda of Understanding, requires the Railroad Commission of Texas and the Texas Commission on Environmental Quality to adopt a memorandum of understanding (MOU) defining the agencies' respective duties under Texas Health and Safety Code, Chapter 401, relating to radioactive materials and other sources of radiation. Texas Health and Safety Code, §401.415, relating to oil and gas naturally occurring radioactive material (NORM) waste, provides that the Railroad Commission of Texas shall issue rules on the management of oil and gas NORM waste, and in so doing shall consult with the Texas Natural Resource Conservation Commission (now TCEQ) and the Department of Health (now Department of State Health Services) regarding protection of the public health and the environment.

(3) Texas Water Code, Chapters 26 and 27, provide that the Railroad Commission and TCEQ collaborate on matters related to discharges, surface water quality, groundwater protection, underground injection control and geologic storage of carbon dioxide. Texas Water Code, §27.049, relating to Memorandum of Understanding, requires the RRC and TCEQ to adopt a new MOU or amend the existing MOU to reflect the agencies' respective duties under Texas Water Code, Chapter 27, Subchapter C-1 (relating to Geologic Storage and Associated Injection of Anthropogenic Carbon Dioxide).

(4) The original MOU between the agencies adopted pursuant to House Bill 1407 (67th Legislature, 1981) became effective January 1, 1982. The MOU was revised effective December 1, 1987, May 31, 1998, August 30, 2010, and again on May 1, 2012, to reflect legislative clarification of the Railroad Commission's jurisdiction over oil and gas wastes and the Texas Natural Resource Conservation Commission's (the combination of the Texas Water Commission, the Texas Air Control Board, and portions of the Texas Department of Health) jurisdiction over industrial and hazardous wastes.

(5) The agencies have determined that the revised MOU that became effective on May 1, 2012, should again be revised to further clarify jurisdictional boundaries and to reflect legislative changes in agency responsibility.

(b) General agency jurisdictions.

(1) Texas Commission on Environmental Quality (TCEQ) (the successor agency to the Texas Natural Resource Conservation Commission).

(A) Solid waste. Under Texas Health and Safety Code, Chapter 361, §§361.001 - 361.754, the TCEQ has jurisdiction over solid waste. The TCEQ's jurisdiction encompasses hazardous and nonhazardous, industrial and municipal, solid wastes.

(i) Under Texas Health and Safety Code, §361.003(34), solid waste under the jurisdiction of the TCEQ is defined to include "garbage, rubbish, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities."

(ii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste excludes "material which results from activities associated with the exploration, development, or production of oil or gas or geothermal resources and other substance or material regulated by the Railroad Commission of Texas pursuant to Section 91.101, Natural Resources Code. . . ."

(iii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste includes the following until the United States Environmental Protection Agency (EPA) delegates its authority under the Resource Conservation and Recovery Act, 42 United States Code (U.S.C.) §6901, et seq., (RCRA) to the RRC: "waste, substance or material that results from activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is a hazardous waste as defined by the administrator of the EPA. . . ."

(iv) After delegation of RCRA authority to the RRC, the definition of solid waste (which defines TCEQ's jurisdiction) will not include hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, or reservoir pressure maintenance or repressurizing plants. The term natural gas or natural gas liquids processing plant refers to a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment is considered a part of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. Further, a pressure maintenance or repressurizing plant is a plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurization) in a natural gas recycling project. A compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system is not a pressure maintenance or repressurizing plant.

(B) Water quality.

(i) Discharges under Texas Water Code, Chapter 26. Under the Texas Water Code, Chapter 26, the TCEQ has jurisdiction over discharges into or adjacent to water in the state, except for discharges regulated by the RRC. Upon delegation from the United States Environmental Protection Agency to the TCEQ of authority to issue permits for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. For the purposes of TCEQ's implementation of Texas Water Code, §26.131, "produced water" is defined as all wastewater associated with oil and gas exploration, development, and production activities, except hydrostatic test water and gas plant effluent, that is discharged into water in the state, including waste streams regulated by 40 CFR Part 435.

(ii) Discharge permits existing on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. RRC permits issued prior to TCEQ delegation of NPDES authority shall remain effective until revoked or expired. Amendment or renewal of such permits on or after the effective date of delegation shall be pursuant to TCEQ's TPDES authority. The TPDES permit will supersede and replace the RRC permit. For facilities that have both an RRC permit and an EPA permit, TCEQ will issue the TPDES permit upon amendment or renewal of the RRC or EPA permit, whichever occurs first.

(iii) Discharge applications pending on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. TCEQ shall assume authority for discharge applications pending at the time TCEQ receives delegation from EPA. The RRC will provide TCEQ the permit application and any other relevant information necessary to administratively and technically review and process the applications. TCEQ will review and process these pending applications in accordance with TPDES requirements.

(iv) Storm water. TCEQ has jurisdiction over storm water discharges that are required to be permitted pursuant to Title 40 Code of Federal Regulations (CFR) Part 122.26, except for discharges regulated by the RRC. Discharge of storm water regulated by TCEQ may be authorized by an individual Texas Pollutant Discharge Elimination System (TPDES) permit or by a general TPDES permit. These storm water permits may also include authorizations for certain minor types of non-storm water discharges.

(I) Storm water associated with industrial activities. The TCEQ regulates storm water discharges associated with certain industrial activities under individual TPDES permits and under the TPDES Multi-Sector General Permit, except for discharges associated with industrial activities under the jurisdiction of the RRC.

(II) Storm water associated with construction activities. The TCEQ regulates storm water discharges associated with construction activities, except for discharges from construction activities under the jurisdiction of the RRC.

(III) Municipal storm water discharges. The TCEQ has jurisdiction over discharges from regulated municipal storm sewer systems (MS4s).

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the TCEQ, and a portion of a site is regulated by the EPA and RRC, storm water authorization must be obtained from the TCEQ for the portion(s) of the site regulated by the TCEQ, and from the EPA and the RRC, as applicable, for the RRC regulated portion(s) of the site. Discharge of storm water from a facility that stores both refined products intended for off-site use and crude oil in aboveground tanks is regulated by the TCEQ.

(v) State water quality certification. Under the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341), the TCEQ performs state water quality certifications for activities that require a federal license or permit and that may result in a discharge to waters of the United States, except for those activities regulated by the RRC.

(vi) Commercial brine extraction and evaporation. Under Texas Water Code, §26.132, the TCEQ has jurisdiction over evaporation pits operated for the commercial production of brine water, minerals, salts, or other substances that naturally occur in groundwater and that are not regulated by the RRC.

(C) Injection wells. Under the Texas Water Code, Chapter 27, the TCEQ has jurisdiction to regulate and authorize the drilling, construction, operation, and closure of injection wells unless the activity is subject to the jurisdiction of the RRC. Injection wells under TCEQ's jurisdiction are identified in 30 TAC §331.11 (relating to Classification of Injection Wells) and include:

(i) Class I injection wells for the disposal of hazardous, radioactive, industrial or municipal waste that inject fluids below the lower-most formation which within 1/4 mile of the wellbore contains an underground source of drinking water;

(ii) Class III injection wells for the extraction of minerals including solution mining of sodium sulfate, sulfur, potash, phosphate, copper, uranium and the mining of sulfur by the Frasch process;

(iii) Class IV injection wells for the disposal of hazardous or radioactive waste which inject fluids into or above formations that contain an underground source of drinking water; and

(iv) Class V injection wells that are not under the jurisdiction of the RRC, such as aquifer remediation wells, aquifer recharge wells, aquifer storage wells, large capacity septic systems, storm water drainage wells, salt water intrusion barrier wells, and closed loop geothermal wells.

(2) Railroad Commission of Texas (RRC).

(A) Oil and gas waste.

(i) Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, wastes (both hazardous and nonhazardous) resulting from activities associated with the exploration, development, or production of oil or gas or geothermal resources, including storage, handling, reclamation, gathering, transportation, or distribution of crude oil or natural gas by pipeline, prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel, are under the jurisdiction of the RRC, except as noted in clause (ii) of this subparagraph. These wastes are termed "oil and gas wastes." In compliance with Texas Health and Safety Code, §361.025 (relating to exempt activities), a list of activities that generate wastes that are subject to the jurisdiction of the RRC is found at §3.8(a)(30) of this title (relating to Water Protection) and at 30 TAC §335.1 (relating to Definitions), which contains a definition of "activities associated with the exploration, development, and production of oil or gas or geothermal resources." Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of oil and gas naturally occurring radioactive material (NORM) waste that constitutes, is contained in, or has contaminated oil and gas waste.

(ii) Hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants are subject to the jurisdiction of the TCEQ until the RRC is authorized by EPA to administer RCRA. When the RRC is authorized by EPA to administer RCRA, jurisdiction over such hazardous wastes will transfer from the TCEQ to the RRC.

(B) Water quality.

(i) Discharges. Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, the RRC regulates discharges from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil and natural gas by pipeline, and from solution brine mining activities, except that on delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. Discharges regulated by the RRC into or adjacent to water in the state shall not cause a violation of the water quality standards. While water quality standards are established by the TCEQ, the RRC has the responsibility for enforcing any violation of such standards resulting from activities regulated by the RRC. Texas Water Code, Chapter 26, does not require that discharges regulated by the RRC comply with regulations of the TCEQ that are not water quality standards. The TCEQ and the RRC may consult as necessary regarding application and interpretation of

Texas Surface Water Quality Standards.

(ii) Storm water. When required by federal law, authorization for storm water discharges that are under the jurisdiction of the RRC must be obtained through application for a National Pollutant Discharge Elimination System (NPDES) permit with the EPA and authorization from the RRC, as applicable.

(I) Storm water associated with industrial activities. Where required by federal law, discharges of storm water associated with facilities and activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under §3.8 of this title (relating to Water Protection), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain Best Management Practices (BMPs) to minimize discharges of pollutants, including sediment, in storm water to help ensure protection of surface water quality during storm events.

(II) Storm water associated with construction activities. Where required by federal law, discharges of storm water associated with construction activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Activities under RRC jurisdiction include construction of a facility that, when completed, would be associated with the exploration, development, or production of oil or gas or geothermal resources, such as a well site; treatment or storage facility; underground hydrocarbon or natural gas storage facility; reclamation plant; gas processing facility; compressor station; terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility; a carbon dioxide geologic storage facility under the jurisdiction of the RRC; and a gathering, transmission, or distribution pipeline that will transport crude oil or natural gas, including natural gas liquids, prior to refining of such oil or the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The RRC also has jurisdiction over storm water from land disturbance associated with a site survey that is conducted prior to construction of a facility that would be regulated by the RRC. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under §3.8 of this title (relating to Water Protection), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain BMPs to minimize discharges of pollutants, including sediment, in storm water during construction activities to help ensure protection of surface water quality during storm events.

(III) Municipal storm water discharges. Storm water discharges from facilities regulated by the RRC located within an MS4 are not regulated by the TCEQ. However, a municipality may regulate storm water discharges from RRC sites into their MS4.

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the RRC and the EPA, and a portion of a site is regulated by the TCEQ, storm water authorization must be obtained from the EPA and the RRC, as applicable, for the portion(s) of the site under RRC jurisdiction and from the TCEQ for the TCEQ regulated portion(s) of the site. Discharge of storm water from a terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility is under the jurisdiction of the RRC.

(iii) State water quality certification. The RRC performs state water quality certifications, as authorized by the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341) for activities that require a federal license or permit and that may result in any discharge to waters of the United States for those activities regulated by the RRC.

(C) Injection wells. The RRC has jurisdiction over the drilling, construction, operation, and closure of the following injection wells.

(i) Disposal wells. The RRC has jurisdiction under Texas Water Code, Chapter 27, over injection wells used to dispose of oil and gas waste. Texas Water Code, Chapter 27, defines "oil and gas waste" to mean "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material." The term "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources" includes waste associated with transportation of crude oil or natural gas by pipeline pursuant to Texas Natural Resources Code, §91.101.

(ii) Enhanced recovery wells. The RRC has jurisdiction over wells into which fluids are injected for enhanced recovery of oil or natural gas.

(iii) Brine mining. Under Texas Water Code, §27.036, the RRC has jurisdiction over brine mining and may issue permits for injection wells.

(iv) Geologic storage of carbon dioxide. Under Texas Water Code, §27.011 and §27.041, and subject to the review of the legislature based on the recommendations made in the preliminary report described by Section 10, Senate Bill No. 1387, Acts of the 81st Legislature, Regular Session (2009), the RRC has jurisdiction over geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources or a saline formation directly above or below that reservoir and over a well used for such injection purposes regardless of whether the well was initially completed for that purpose or was initially completed for another purpose and converted.

(v) Hydrocarbon storage. The RRC has jurisdiction over wells into which fluids are injected for storage of hydrocarbons that are liquid at standard temperature and pressure.

(vi) Geothermal energy. Under Texas Natural Resources Code, Chapter 141, the RRC has jurisdiction over injection wells for the exploration, development, and production of geothermal energy and associated resources.

(vii) In situ tar sands. Under Texas Water Code, §27.035, the RRC has jurisdiction over the in situ recovery of tar sands and may issue permits for injection wells used for the in situ recovery of tar sands.

(c) Definition of hazardous waste.

(1) Under the Texas Health and Safety Code, §361.003(12), a "hazardous waste" subject to the jurisdiction of the TCEQ is defined as "solid waste identified or listed as a hazardous waste by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended (42 U.S.C. §6901, et seq.)." Similarly, under Texas Natural Resources Code, §91.601(1), "oil and gas hazardous waste" subject to the jurisdiction of the RRC is defined as an "oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §§6901, et seq.)."

(2) Federal regulations adopted under authority of the federal Solid Waste Disposal Act, as amended by RCRA, exempt from regulation as hazardous waste certain oil and gas wastes. Under 40 Code of Federal Regulations (CFR) §261.4(b)(5), "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are described as wastes that are exempt from federal hazardous waste regulations.

(3) A partial list of wastes associated with oil, gas, and geothermal exploration, development, and production that

are considered exempt from hazardous waste regulation under RCRA can be found in EPA's "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," 53 FedReg 25,446 (July 6, 1988). A further explanation of the exemption can be found in the "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, " 58 FedReg 15,284 (March 22, 1993). The exemption codified at 40 CFR §261.4(b)(5) and discussed in the Regulatory Determination has been, and may continue to be, clarified in subsequent guidance issued by the EPA.

(d) Jurisdiction over waste from specific activities.

(1) Drilling, operation, and plugging of wells associated with the exploration, development, or production of oil, gas, or geothermal resources. Wells associated with the exploration, development, or production of oil, gas, or geothermal resources include exploratory wells, cathodic protection holes, core holes, oil wells, gas wells, geothermal resource wells, fluid injection wells used for secondary or enhanced recovery of oil or gas, oil and gas waste disposal wells, and injection water source wells. Several types of waste materials can be generated during the drilling, operation, and plugging of these wells. These waste materials include drilling fluids (including water-based and oil-based fluids), cuttings, produced water, produced sand, waste hydrocarbons (including used oil), fracturing fluids, spent acid, workover fluids, treating chemicals (including scale inhibitors, emulsion breakers, paraffin inhibitors, and surfactants), waste cement, filters (including used oil filters), domestic sewage (including waterborne human waste and waste from activities such as bathing and food preparation), and trash (including inert waste, barrels, dope cans, oily rags, mud sacks, and garbage). Generally, these wastes, whether disposed of by discharge, landfill, land farm, evaporation, or injection, are subject to the jurisdiction of the RRC. Wastes from oil, gas, and geothermal exploration activities subject to regulation by the RRC when those wastes are to be processed, treated, or disposed of at a solid waste management facility authorized by the TCEQ under 30 TAC Chapter 330 are, as defined in 30 TAC §330.3(148) (relating to Definitions), "special wastes."

(2) Field treatment of produced fluids. Oil, gas, and water produced from oil, gas, or geothermal resource wells may be treated in the field in facilities such as separators, skimmers, heater treaters, dehydrators, and sweetening units. Waste that results from the field treatment of oil and gas include waste hydrocarbons (including used oil), produced water, hydrogen sulfide scavengers, dehydration wastes, treating and cleaning chemicals, filters (including used oil filters), asbestos insulation, domestic sewage, and trash are subject to the jurisdiction of the RRC.

(3) Storage of oil.

(A) Tank bottoms and other wastes from the storage of crude oil (whether foreign or domestic) before it enters the refinery are under the jurisdiction of the RRC. In addition, waste resulting from storage of crude oil at refineries is subject to the jurisdiction of the TCEQ.

(B) Wastes generated from storage tanks that are part of the refinery and wastes resulting from the wholesale and retail marketing of refined products are subject to the jurisdiction of the TCEQ.

(4) Underground hydrocarbon storage. The disposal of wastes, including saltwater, resulting from the construction, creation, operation, maintenance, closure, or abandonment of an "underground hydrocarbon storage facility" is subject to the jurisdiction of the RRC, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" have the meanings set out in Texas Natural Resources Code, §91.201.

(5) Underground natural gas storage. The disposal of wastes resulting from the construction, operation, or abandonment of an "underground natural gas storage facility" is subject to the jurisdiction of the RRC, provided that the terms "natural gas" and "storage facility" have the meanings set out in Texas Natural Resources Code, §91.173.

(6) Transportation of crude oil or natural gas.

(A) Jurisdiction over pipeline-related activities. The RRC has jurisdiction over matters related to pipeline safety for pipelines in Texas, as referenced in §8.1 of this title (relating to General Applicability and Standards) pursuant to Chapter 121 of the Texas Utilities Code and Chapter 117 of the Texas Natural Resources Code. The RRC has jurisdiction over spill response and remediation of releases from pipelines transporting crude oil, natural gas, and condensate that originate from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC is responsible for water quality certification issues related to construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines transporting carbon dioxide.

(B) Crude oil and natural gas are transported by railcars, tank trucks, barges, tankers, and pipelines. The RRC has jurisdiction over waste from the transportation of crude oil by pipeline, regardless of the crude oil source (foreign or domestic) prior to arrival at a refinery. The RRC also has jurisdiction over waste from the transportation by pipeline of natural gas, including natural gas liquids, prior to the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The transportation wastes subject to the jurisdiction of the RRC include wastes from pipeline compressor or pressure stations and wastes from pipeline hydrostatic pressure tests and other pipeline operations. These wastes include waste hydrocarbons (including used oil), treating and cleaning chemicals, filters (including used oil filters), scraper trap sludge, trash, domestic sewage, wastes contaminated with polychlorinated biphenyls (PCBs) (including transformers, capacitors, ballasts, and soils), soils contaminated with mercury from leaking mercury meters, asbestos insulation, transite pipe, and hydrostatic test waters.

(C) The TCEQ has jurisdiction over waste from transportation of refined products by pipeline.

(D) The TCEQ also has jurisdiction over wastes associated with transportation of crude oil and natural gas, including natural gas liquids, by railcar, tank truck, barge, or tanker.

(7) Reclamation plants.

(A) The RRC has jurisdiction over wastes from reclamation plants that process wastes from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, such as lease tank bottoms. Waste management activities of reclamation plants for other wastes are subject to the jurisdiction of the TCEQ.

(B) The RRC has jurisdiction over the conservation and prevention of waste of crude oil and therefore must approve all movements of crude oil-containing materials to reclamation plants. The applicable statute and regulations consist primarily of reporting requirements for accounting purposes.

(8) Refining of oil.

(A) The management of wastes resulting from oil refining operations, including spent caustics, spent catalysts, still bottoms or tars, and American Petroleum Institute (API) separator sludges, is subject to the jurisdiction of the TCEQ. The processing of light ends from the distillation and cracking of crude oil or crude oil products is considered to be a refining operation. The term "refining" does not include the processing of natural gas or natural gas liquids.

(B) The RRC has jurisdiction over refining activities for the conservation and the prevention of waste of crude oil. The RRC requires that all crude oil streams into or out of a refinery be reported for accounting purposes. In addition, the RRC requires that materials recycled and used as a fuel, such as still bottoms or waste crude oil, be reported.

(9) Natural gas or natural gas liquids processing plants (including gas fractionation facilities) and pressure maintenance or repressurizing plants. Wastes resulting from activities associated with these facilities include produced water, cooling tower water, sulfur bead, sulfides, spent caustics, sweetening agents, spent catalyst, waste hydrocarbons (including used oil), asbestos insulation, wastes contaminated with PCBs (including transformers, capacitors, ballasts, and soils), treating and cleaning chemicals, filters, trash, domestic sewage, and dehydration materials. These wastes are subject to the jurisdiction of the RRC under Texas Natural Resources Code, §1.101. Disposal of waste from activities associated with natural gas or natural gas liquids processing plants (including gas fractionation facilities), and pressure maintenance or repressurizing plants by injection is subject to the jurisdiction of the RRC under Texas Water Code, Chapter 27. However, until delegation of authority under RCRA to the RRC, the TCEQ shall have jurisdiction over wastes resulting from these activities that are not exempt from federal hazardous waste regulation under RCRA and that are considered hazardous under applicable federal rules.

(10) Manufacturing processes.

(A) Wastes that result from the use of natural gas, natural gas liquids, or products refined from crude oil in any manufacturing process, such as the production of petrochemicals or plastics, or from the manufacture of carbon black, are industrial wastes subject to the jurisdiction of the TCEQ. The term "manufacturing process" does not include the processing (including fractionation) of natural gas or natural gas liquids at natural gas or natural gas liquids processing plants.

(B) The RRC has jurisdiction under Texas Natural Resources Code, Chapter 87, to regulate the use of natural gas in the production of carbon black.

(C) Biofuels. The TCEQ has jurisdiction over wastes associated with the manufacturing of biofuels and biodiesel. TCEQ Regulatory Guidance Document RG-462 contains additional information regarding biodiesel manufacturing in the state of Texas.

(11) Commercial service company facilities and training facilities.

(A) The TCEQ has jurisdiction over wastes generated at facilities, other than actual exploration, development, or production sites (field sites), where oil and gas industry workers are trained. In addition, the TCEQ has jurisdiction over wastes generated at facilities where materials, processes, and equipment associated with oil and gas industry operations are researched, developed, designed, and manufactured. However, wastes generated from tests of materials, processes, and equipment at field sites are under the jurisdiction of the RRC.

(B) The TCEQ also has jurisdiction over waste generated at commercial service company facilities operated by persons providing equipment, materials, or services (such as drilling and work over rig rental and tank rental; equipment repair; drilling fluid supply; and acidizing, fracturing, and cementing services) to the oil and gas industry. These wastes include the following wastes when they are generated at commercial service company facilities: empty sacks, containers, and drums; drum, tank, and truck rinsate; sandblast media; painting wastes; spent solvents; spilled chemicals; waste motor oil; and unused fracturing and acidizing fluids.

(C) The term "commercial service company facility" does not include a station facility such as a warehouse, pipeyard, or equipment storage facility belonging to an oil and gas operator and used solely for the support of that operator's own activities associated with the exploration, development, or production activities.

(D) Notwithstanding subparagraphs (A) - (C) of this paragraph, the RRC has jurisdiction over disposal of oil and gas wastes, such as waste drilling fluids and NORM-contaminated pipe scale, in volumes greater than the incidental volumes usually received at such facilities, that are managed at commercial service company facilities.

(E) The RRC also has jurisdiction over wastes such as vacuum truck rinsate and tank rinsate generated at facilities operated by oil and gas waste haulers permitted by the RRC pursuant to §3.8(f) of this title (relating to Water Protection).

(12) Mobile offshore drilling units (MODUs). MODUs are vessels capable of engaging in drilling operations for exploring or exploiting subsea oil, gas, or mineral resources.

(A) The RRC and, where applicable, the EPA, the U.S. Coast Guard, or the Texas General Land Office (GLO), have jurisdiction over discharges from an MODU when the unit is being used in connection with activities associated with the exploration, development, or production of oil or gas or geothermal resources, except that upon delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code, §26.131(a), the TCEQ shall assume RRC's authority under this subsection.

(B) The TCEQ and, where applicable, the EPA, the U.S. Coast Guard, or the GLO, have jurisdiction over discharges from an MODU when the unit is being serviced at a maintenance facility.

(C) Where applicable, the EPA, the U.S. Coast Guard, or the GLO has jurisdiction over discharges from an MODU during transportation from shore to exploration, development or production site, transportation between sites, and transportation to a maintenance facility.

(e) Interagency activities.

(1) Recycling and pollution prevention.

(A) The TCEQ and the RRC encourage generators to eliminate pollution at the source and recycle whenever possible to avoid disposal of wastes. Questions regarding source reduction and recycling may be directed to the TCEQ External Relations Division, or to the RRC. The TCEQ may require generators to explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the RRC at a facility regulated by the TCEQ; similarly, the RRC may explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the TCEQ at a facility regulated by the RRC.

(B) The TCEQ External Relations Division and the RRC will coordinate as necessary to maintain a working relationship to enhance the efforts to share information and use resources more efficiently. The TCEQ External Relations Division will make the proper TCEQ personnel aware of the services offered by the RRC, share information with the RRC to maximize services to oil and gas operators, and advise oil and gas operators of RRC services. The RRC will make the proper RRC personnel aware of the services offered by the TCEQ External Relations Division, share information with the TCEQ External Relations Division to maximize services to industrial operators, and advise industrial operators of the TCEQ External Relations Division services.

(2) Treatment of wastes under RRC jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K, (relating to Storage, Treatment, and Reuse Procedures for Petroleum-Substance Contaminated Soil).

(A) Soils contaminated with constituents that are physically and chemically similar to those normally found in soils at leaking underground petroleum storage tanks from generators under the jurisdiction of the RRC are eligible for treatment at TCEQ regulated soil treatment facilities once alternatives for recycling and source reduction have been explored. For the purpose of this provision, soils containing petroleum substance(s) as defined in 30 TAC §334.481 (relating to Definitions) are considered to be similar, but drilling muds, acids, or other chemicals used in oil and gas activities are not considered similar. Generators under the jurisdiction of the RRC must meet the same requirements as generators under the jurisdiction of the TCEQ when sending their petroleum contaminated soils to soil treatment facilities under TCEQ jurisdiction. Those requirements are in 30 TAC §334.496 (relating to Shipping Procedures Applicable to Generators of Petroleum-Substance Waste), except subsection (c) which is not applicable, and 30 TAC §334.497 (relating to Recordkeeping and Reporting Procedures Applicable to Generators). RRC generators with questions on these requirements should contact the TCEQ.

(B) Generators under RRC jurisdiction should also be aware that TCEQ regulated soil treatment facilities are required by 30 TAC §334.499 (relating to Shipping Requirements Applicable to Owners or Operators of Storage, Treatment, or Disposal Facilities) to maintain documentation on the soil sampling and analytical methods, chain-of-custody, and all analytical results for the soil received at the facility and transported off-site or reused on-site.

(C) The RRC must specifically authorize management of contaminated soils under its jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations.

(D) All waste, including treated waste, subject to the jurisdiction of the RRC and managed at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K will remain subject to the jurisdiction of the

RRC. Such materials will be subject to RRC regulations regarding final reuse, recycling, or disposal.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K.

(3) Processing, treatment, and disposal of wastes under RRC jurisdiction at facilities authorized by the TCEQ.

(A) As provided in this paragraph, waste materials subject to the jurisdiction of the RRC may be managed at solid waste facilities under the jurisdiction of the TCEQ once alternatives for recycling and source reduction have been explored. The RRC must specifically authorize management of wastes under its jurisdiction at facilities regulated by the TCEQ. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations. In addition, except as provided in subparagraph (B) of this paragraph, the concurrence of the TCEQ is required to manage "special waste" under the jurisdiction of the RRC at a facility regulated by the TCEQ. The TCEQ's concurrence may be subject to specified conditions.

(B) A facility under the jurisdiction of the TCEQ may accept, without further individual concurrence, waste under the jurisdiction of the RRC if that facility is permitted or otherwise authorized to accept that particular type of waste. The phrase "that type of waste" does not specifically refer to waste under the jurisdiction of the RRC, but rather to the waste's physical and chemical characteristics. Management and disposal of waste under the jurisdiction of the RRC is subject to TCEQ's rules governing both special waste and industrial waste.

(C) If the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization, individual written concurrences from the TCEQ shall be required to manage wastes under the jurisdiction of the RRC at TCEQ regulated facilities. Recommendations for the management of special wastes associated with the exploration, development, or production of oil, gas, or geothermal resources are found in TCEQ Regulatory Guidance document RG-3. (This is required only if the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization provided by the TCEQ.) To obtain an individual concurrence, the waste generator must provide to the TCEQ sufficient information to allow the concurrence determination to be made, including the identity of the proposed waste management facility, the process generating the waste, the quantity of waste, and the physical and chemical nature of the waste involved (using process knowledge and/or laboratory analysis as defined in 30 TAC Chapter 335, Subchapter R (relating to Waste Classification)). In obtaining TCEQ approval, generators may use their existing knowledge about the process or materials entering it to characterize their wastes. Material Safety Data Sheets, manufacturer's literature, and other documentation generated in conjunction with a particular process may be used. Process knowledge must be documented and submitted with the request for approval.

(D) Domestic septage collected from portable toilets at facilities subject to RRC jurisdiction that is not mixed with other waste materials may be managed at a facility permitted by the TCEQ for disposal, incineration, or land application for beneficial use of such domestic septage waste without specific authorization from the TCEQ or the RRC. Waste sludge subject to the jurisdiction of the RRC may not be applied to the land at a facility permitted by the TCEQ for the beneficial use of sewage sludge or water treatment sludge.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities under the jurisdiction of the TCEQ. If a receiving facility requires a TCEQ waste code for waste under the jurisdiction of the RRC, a code consisting of the following may be provided:

(i) the sequence number "RRCT";

(ii) the appropriate form code, as specified in 30 TAC Chapter 335, Subchapter R, §335.521, Appendix 3 (relating to Appendices); and

(iii) the waste classification code "H" if the waste is a hazardous oil and gas waste, or "R" if the waste is a nonhazardous oil and gas waste.

(F) If a facility requests or requires a TCEQ waste generator registration number for wastes under the jurisdiction of the RRC, the registration number "XXXRC" may be provided.

(G) Wastes that are under the jurisdiction of the RRC need not be reported to the TCEQ.

(4) Management of nonhazardous wastes under TCEQ jurisdiction at facilities regulated by the RRC.

(A) Once alternatives for recycling and source reduction have been explored, and with prior authorization from the RRC, the following nonhazardous wastes subject to the jurisdiction of the TCEQ may be disposed of, other than by injection into a Class II well, at a facility regulated by the RRC; bioremediated at a facility regulated by the RRC (prior to reuse, recycling, or disposal); or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous wastes that are chemically and physically similar to oil and gas wastes, but excluding soils, media, debris, sorbent pads, and other clean-up materials that are contaminated with refined petroleum products.

(B) To obtain an individual authorization from the RRC, the waste generator must provide the following information, in writing, to the RRC: the identity of the proposed waste management facility, the quantity of waste involved, a hazardous waste determination that addresses the process generating the waste and the physical and chemical nature of the waste, and any other information that the RRC may require. As appropriate, the RRC shall reevaluate any authorization issued pursuant to this paragraph.

(C) Once alternatives for recycling and source reduction have been explored, and subject to the RRC's individual authorization, the following wastes under the jurisdiction of the TCEQ are authorized without further TCEQ approval to be disposed of at a facility regulated by the RRC, bioremediated at a facility regulated by the RRC, or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous bottoms from tanks used only for crude oil storage; unused and/or reconditioned drilling and completion/workover wastes from commercial service company facilities; used and/or unused drilling and completion/workover wastes generated at facilities where workers in the oil and gas exploration, development, and production industry are trained; used and/or unused drilling and completion/workover wastes generated at facilities where materials, processes, and equipment associated with oil and gas exploration, development, and production operations are researched, developed, designed, and manufactured; unless other provisions are made in the underground injection well permit used and/or unused drilling and completion wastes (but not workover wastes) generated in connection with the drilling and completion of Class I, III, and V injection wells; wastes (such as contaminated soils, media, debris, sorbent pads, and other cleanup materials) associated with spills of crude oil and natural gas liquids if such wastes are under the jurisdiction of the TCEQ; and sludges from washout pits at commercial service company facilities.

(D) Under Texas Water Code, §27.0511(g), a TCEQ permit is required for injection of industrial or municipal waste as an injection fluid for enhanced recovery purposes. However, under §27.0511(h), the RRC may authorize a person to use nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals as an injection fluid for enhanced recovery purposes without obtaining a permit from the TCEQ. The use or disposal of radioactive material under this subparagraph is subject to the applicable requirements of Texas Health and Safety Code, Chapter 401.

(E) Under Texas Water Code, §27.026, by individual permit, general permit, or rule, the TCEQ may designate a Class II disposal well that has an RRC permit as a Class V disposal well authorized to dispose by injection nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals under the jurisdiction of the TCEQ. The operator of a permitted Class II disposal well seeking a Class V authorization must apply to TCEQ and obtain a Class V authorization prior to disposal of nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals. A permitted Class II disposal well that has obtained a Class V authorization from TCEQ under Texas Water Code, §27.026, remains subject to the regulatory requirements of both the RRC and the TCEQ. Nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals to be disposed by injection in a permitted Class II disposal well authorized by TCEQ as a Class V injection well remain subject to the requirements of the Texas Health and Safety Code, the Texas Water Code, and the TCEQ's rules. The RRC and the TCEQ may impose additional requirements or conditions to address the dual injection activity under Texas Water Code, §27.026.

(5) Drilling in landfills. The TCEQ will notify the Oil and Gas Division of the RRC and the landfill owner at the time a drilling application is submitted if an operator proposes to drill a well through a landfill regulated by the TCEQ. The RRC and the TCEQ will cooperate and coordinate with one another in advising the appropriate parties of measures necessary to reduce the potential for the landfill contents to cause groundwater contamination as a result of landfill disturbance associated with drilling operations. The TCEQ requires prior written approval before drilling of any test borings through previously deposited municipal solid waste under 30 TAC §330.15 (relating to General Prohibitions), and before borings or other penetration of the final cover of a closed municipal solid waste landfill under 30 TAC §330.955 (relating to Miscellaneous). The installation of landfill gas recovery wells for the recovery and beneficial reuse of landfill gas is under the jurisdiction of the TCEQ in accordance with 30 TAC Chapter 330, Subchapter I (relating to Landfill Gas Management). Modification of an active or a closed solid waste management unit, corrective action management unit, hazardous waste landfill cell, or industrial waste landfill cell by drilling or penetrating into or through deposited waste may require prior written approval from TCEQ. Such approval may require a new authorization from TCEQ or modification or amendment of an existing TCEQ authorization.

(6) Coordination of actions and cooperative sharing of information.

(A) In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the TCEQ at a facility permitted by the RRC, the TCEQ is responsible for enforcement actions against the generator or transporter, and the RRC is responsible for enforcement actions against the disposal facility. In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the RRC at a facility permitted by the TCEQ, the RRC is responsible for enforcement actions against the generator or transporter, and the TCEQ is responsible for enforcement actions against the disposal facility.

(B) The TCEQ and the RRC agree to cooperate with one another by sharing information. Employees of either agency who receive a complaint or discover, in the course of their official duties, information that indicates a violation of a statute, regulation, order, or permit pertaining to wastes under the jurisdiction of the other agency, will notify the other agency. In addition, to facilitate enforcement actions, each agency will share information in its possession with the other agency if requested by the other agency to do so.

(C) The TCEQ and the RRC agree to work together at allocating respective responsibilities. To the extent that jurisdiction is indeterminate or has yet to be determined, the TCEQ and the RRC agree to share information and take appropriate investigative steps to assess jurisdiction.

(D) For items not covered by statute or rule, the TCEQ and the RRC will collaborate to determine respective responsibilities for each issue, project, or project type.

(E) The staff of the RRC and the TCEQ shall coordinate as necessary to attempt to resolve any disputes regarding interpretation of this MOU and disputes regarding definitions and terms of art.

(7) Groundwater.

(A) Notice of groundwater contamination. Under Texas Water Code, §26.408, effective September 1, 2003, the RRC must submit a written notice to the TCEQ of any documented cases of groundwater contamination that may affect a drinking water well.

(B) Groundwater protection letters. The RRC provides letters of recommendation concerning groundwater protection.

(i) For recommendations related to normal drilling operations, shot holes for seismic surveys, and cathodic protection wells, the RRC provides geologic interpretation identifying fresh water zones, base of usable-quality water (generally less than 3,000 mg/L total dissolved solids, but may include higher levels of total dissolved solids if identified as currently being used or identified by the Texas Water Development Board as a source of water for desalination), and include protection depths recommended by the RRC. The geological interpretation may include groundwater protection based on potential hydrological connectivity to usable-quality water.

(ii) For recommendations related to injection, the RRC provides geologic interpretation of the base of the underground source of drinking water. The term "underground source of drinking water" is defined in 40 Code of Federal Regulations §146.3 (Federal Register, Volume 46, June 24, 1980).

(8) Emergency and spill response.

(A) The TCEQ and the RRC are members of the state's Emergency Management Council. The TCEQ is the state's primary agency for emergency support during response to hazardous materials and oil spill incidents. The TCEQ is responsible for state-level coordination of assets and services, and will identify and coordinate staffing requirements appropriate to the incident to include investigative assignments for the primary and support agencies.

(B) Contaminated soil and other wastes that result from a spill must be managed in accordance with the governing statutes and regulations adopted by the agency responsible for the activity that resulted in the spill. Coordination of issues of spill notification, prevention, and response shall be addressed in the State of Texas Oil and Hazardous Substance Spill Contingency Plan and may be addressed further in a separate Memorandum of Understanding among these agencies and other appropriate state agencies.

(C) The agency (TCEQ or RRC) that has jurisdiction over the activity that resulted in the spill incident will be responsible for measures necessary to monitor, document, and remediate the incident.

(i) The TCEQ has jurisdiction over certain inland oil spills, all hazardous-substance spills, and spills of other substances that may cause pollution.

(ii) The RRC has jurisdiction over spills or discharges from activities associated with the exploration, development, or production of crude oil, gas, and geothermal resources, and discharges from brine mining or surface mining.

(D) If TCEQ or RRC field personnel receive spill notifications or reports documenting improperly managed waste or contaminated environmental media resulting from a spill or discharge that is under the jurisdiction of the other agency, they shall refer the issue to the other agency. The agency that has jurisdiction over the activity that resulted in the improperly managed waste, spill, discharge, or contaminated environmental media will be responsible for measures necessary to monitor, document, and remediate the incident.

(9) Anthropogenic carbon dioxide storage. In determining the proper permitting agency in regard to a particular permit application for a carbon dioxide geologic storage project, the TCEQ and the RRC will coordinate by any appropriate means to review proposed locations, geologic settings, reservoir data, and other jurisdictional criteria specified in Texas Water Code, §27.041.

(f) Radioactive material.

(1) Radioactive substances. Under the Texas Health and Safety Code, §401.011, the TCEQ has jurisdiction to regulate and license:

(A) the disposal of radioactive substances;

(B) the processing or storage of low-level radioactive waste or NORM waste from other persons, except oil and gas NORM waste;

(C) the recovery or processing of source material;

(D) the processing of by-product material as defined by Texas Health and Safety Code, §401.003(3)(B); and

(E) sites for the disposal of low-level radioactive waste, by-product material, or NORM waste.

(2) NORM waste.

(A) Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of NORM waste that constitutes, is contained in, or has contaminated oil and gas waste. This waste material is called "oil and gas NORM waste." Oil and gas NORM waste may be generated in connection with the exploration, development, or production of oil or gas.

(B) Under Texas Health and Safety Code, §401.412, the TCEQ has jurisdiction over the disposal of NORM that is not oil and gas NORM waste.

(C) The term "disposal" does not include receipt, possession, use, processing, transfer, transport, storage, or commercial distribution of radioactive materials, including NORM. These non-disposal activities are under the jurisdiction of the Texas Department of State Health Services under Texas Health and Safety Code, §401.011(a).

(3) Drinking water residuals. A person licensed for the commercial disposal of NORM waste from public water systems may dispose of NORM waste only by injection into a Class I injection well permitted under 30 TAC Chapter 331 (relating to Underground Injection Control) that is specifically permitted for the disposal of NORM waste.

(4) Management of radioactive tracer material.

(A) Radioactive tracer material is subject to the definition of low-level radioactive waste under Texas Health and Safety Code, §401.004, and must be handled and disposed of in accordance with the rules of the TCEQ and the Department of State Health Services.

(B) Exemption. Under Texas Health and Safety Code, §401.106, the TCEQ may grant an exemption by rule from a licensing requirement if the TCEQ finds that the exemption will not constitute a significant risk to the public health and safety and the environment.

(5) Coordination with the Texas Radiation Advisory Board. The RRC and the TCEQ will consider recommendations and advice provided by the Texas Radiation Advisory Board that concern either agency's policies or programs related to the development, use, or regulation of a source of radiation. Both agencies will provide written response to the recommendations or advice provided by the advisory board.

(6) Uranium exploration and mining.

(A) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium exploration activities.

(B) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium mining, except for in situ recovery processes.

(C) Under Texas Water Code, §27.0513, the TCEQ has jurisdiction over injection wells used for uranium mining.

(D) Under Texas Health and Safety Code, §401.2625, the TCEQ has jurisdiction over the licensing of source material recovery and processing or for storage, processing, or disposal of by-product material.

(g) Effective date. This Memorandum of Understanding, as of its July 15, 2020, effective date, shall supersede the prior Memorandum of Understanding among the agencies, dated May 1, 2012.

Source Note: The provisions of this §3.30 adopted to be effective May 31, 1998, 23 TexReg 5427; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective August 30, 2010, 35 TexReg 7728; amended to be effective May 1, 2012, 37 TexReg 2385; amended to be effective July 15, 2020, 45 TexReg 4503.

§3.31 Gas Reservoirs and Gas Well Allowable

(a) General.

(1) Allowables of gas wells not currently assigned an allowable will not be made effective:

(A) prior to the well's completion or reclassification date; or

(B) more than 15 days prior to the date all reports or information necessary to the assignment of an allowable are received in the appropriate commission office.

(2) If a report or item of information necessary to the assignment of an allowable is not filed on time, there shall be a one-day allowable reduction for each day the report or information is late.

(b) Changes in gas well allowables.

(1) Changes in allowable of gas wells currently assigned an allowable will be effective on the date of the test or date of the change affecting the well's allowable (when the operator submits special tests or information), provided this is not more than 15 days prior to the date the special test or information is received in the appropriate Commission office.

(2) With respect to a multicompleted well, the allowable of the second and succeeding zones will be made effective no earlier than the date the last report or item necessary for the assignment of an allowable is received in the appropriate Commission office.

(3) When a well is recompleted as a gas well in a different field, any overproduction that has occurred in the old field must be made up before an allowable will be assigned in the new field.

(4) The maximum daily allowable for a horizontal drainhole gas well or a gas well in a designated unconventional fracture treated (UFT) field is set forth in §3.86(d)(4) and (5) of this title (relating to Horizontal Drainhole Wells).

is shut in or curtailed, and waste, as defined in the Texas Natural Resource Code, Title 3, is found by the commission to exist, neither a special marketing program purchaser nor its affiliated first purchaser may purchase lower priority category gas until all the priority Category 1, 2, and 3 gas is taken and resulting waste is prevented. The commission shall expedite determination of waste, and may enter an emergency, temporary, or interim order upon application and affidavit proof that waste is occurring. The application and affidavit proof must be accompanied by supporting documentation, including data on well performance, and a statement that the application and affidavit proof has been served on the first purchaser(s) of the subject well(s) and any affiliated special marketing program purchaser using the first purchaser(s) same pipeline system on or before the date the application and affidavit proof has been mailed or delivered to the commission, with the opportunity for the first purchaser to respond within five days of service or of commission receipt, whichever is latest.

(5) The affiliated first purchaser must continue in compliance with this section to purchase and accept delivery from the wells for which the offer was made and not accepted.

(6) With respect to the purchase of gas from those that accept an offer made pursuant to this subsection, the special marketing program purchaser must comply with this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) as a separate first purchaser.

(7) It is not the objective of this subsection to abrogate any existing contract rights or obligations.

(l) Sellers' complaint procedure. Any operator or nonoperator that is denied by the first purchaser in violation of this section or §3.28 or §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) the opportunity to produce a well's ratable share of gas or opportunity for a well to participate in a special marketing program may file a complaint with the commission and request the commission to direct the first purchaser to end the discriminatory practices. A complainant may request a hearing regarding alleged discriminatory practices or to determine whether a first purchaser is or has, through gas exchange agreements or through actions of its affiliate(s), denied an operator a reasonable opportunity to market its gas.

(m) Purchasers' complaint procedure. If after reasonable notice by the purchaser, an operator fails to comply with a first purchaser's request to reduce production ratably in compliance with this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) the purchaser may file a complaint with the commission and request the commission to direct the operator to comply with the purchaser's requests to reduce production ratably. The complainant or the operator may request the commission to take further action, including setting the issue for hearing.

(n) Hardship exceptions. If the operation of this section or §3.28 or §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) causes undue hardship, the commission may, after proper notice and hearing, grant an exception or take appropriate action, including action to prevent waste or protect correlative rights.

(o) Severability provisions. If any provision of this section or its application to any person or circumstance is held invalid, the invalidity shall not affect other provisions or applications of the section which can be given effect without the invalid provisions or appreciation, and the provisions of the section are declared to be severable.

Source Note: The provisions of this §3.34 adopted to be effective September 1, 1986, 11 TexReg 3691; amended to be effective March 2, 1987, 12 TexReg 536; amended to be effective September 8, 1987, 12 TexReg 2860; amended to be effective February 29, 1988, 13 TexReg 838; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.35 Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned

(a) Abandonment of radioactive source.

(1) Immediate notice of the loss of a radioactive source shall be filed by the operator with the commission designating the location, by county, survey name and abstract number, lease name and well number, distances from survey boundaries and Lambert Coordinates.

(2) Procedures for recovery of the lost radioactive source will be furnished to the commission and such radioactive source shall not be declared abandoned until all reasonable effort has been expended to retrieve the tool.

(3) The operator shall erect, under supervision of the commission, a standardized permanent surface marker as a visual warning to any person who may reenter the hole for any reason, showing that it contains a radioactive source. This marker shall contain the following information: well name, commission number, surface location, name of the operator, name of the lease, the source or material abandoned in the well, the total depth of the well, the depth at which the source is abandoned, the plug back depth, the date of the abandonment of the source, the activity of the source, and a warning not to drill below the plug back depth.

(b) Abandonment procedures.

(1) Wells in which radioactive sources are abandoned shall be mechanically equipped so as to prevent either

accidental or intentional mechanical disintegration of the radioactive source.

(A) Sources abandoned in the bottom of the well shall be covered with a substantial standard color dyed (red iron oxide) cement plug on top of which a whipstock or other approved deflection device shall be set. The dye is to alert the reentry operator prior to encountering the source.

(B) Upon abandoning the well in which a logging source has been cemented in place behind a casing string above total depth, a standard color dyed cement plug shall be placed opposite the abandoned source and a whipstock or other approved deflection device placed on top of the plug.

(C) In the event the operator finds that after expending a reasonable effort, because of hole conditions, it is not possible to abandon the source as prescribed in subparagraphs (A) and (B) of this paragraph, he shall seek commission approval to an alternate abandonment procedure.

(D) When a logging source must be abandoned in a producing zone, a standard color dyed cement plug shall be set and a whipstock or other approved deflection device placed above to direct the sidetrack at least 15 feet away from the source.

(2) Upon permanent abandonment of any well in which a radioactive source is left in the hole, and after removal of the wellhead, a permanent plaque shall be attached to the top of the casing left in the hole in such a manner that reentry cannot be accomplished without disturbing the plaque. This plaque shall serve as a visual warning to any person reentering the hole that a radioactive source has been abandoned in place in the well. The plaque shall contain the trefoil radiation symbol with a radioactive warning and shall be constructed of a long-lasting material such as monel, stainless steel, or brass, in accordance with specifications established by the commission. The plugging report filed with the commission shall identify the well as an abandoned radioactive source well, and shall show compliance with the procedures required by this section.

(3) The commission will maintain a current listing of all abandoned radioactive source wells, and each district office will keep such a list for radioactive source wells in that district.

Source Note: The provisions of this §3.35 adopted to be effective January 1, 1976.

§3.36 Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas

(a) Applicability. Each operator who conducts operations as described in paragraph (1) of this subsection shall be subject to this section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide. This section applies to both intentional and accidental releases of hydrogen sulfide.

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas, to the extent as specified in subsection (c) of this section, general provisions.

(2) This section shall not apply to:

(A) operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modification, such as refining, petrochemical plants, or chemical plants;

(B) operations involving gathering, storing, and transporting stabilized liquid hydrocarbons;

(C) operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

(b) Definitions.

(1) Industrial modification--This term is used to identify those operations related to refining, petrochemical plants, and chemical plants. The term does not include field processing such as that performed by gasoline plants and their associated gathering systems.

(2) Stabilized liquid hydrocarbon--The product of a production operation in which the entrained gaseous hydrocarbons have been removed to the degree that said liquid may be stored at atmospheric conditions.

(3) Radius of exposure--That radius constructed with the point of escape as its starting point and its length calculated as provided for in subsection (c)(2) of this section.

(4) Area of exposure--The area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

(5) Public area--A dwelling, place of business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can expect to be populated.

(6) Public road--Any federal, state, county, or municipal street or road owned or maintained for public access or use.

(7) Sulfide stress cracking--The cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

(8) Facility modification--Any change in the operation such as an increase in throughput, in excess of the

designed capacity, or any change that would increase the radius of exposure.

(9) Public infringement--This shall mean that a public area and/or a public road, or both, has been established within an area of exposure to the degree that such infringement would change the applicable provisions of this rule to those operations responsible for creating the area of exposure.

(10) Potentially hazardous volume of hydrogen sulfide--A volume of hydrogen sulfide gas of such concentration that:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road; or

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road; or

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(11) Contingency plan--A written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(12) Reaction-type contingency plan--A preplanned, written procedure for alerting and protecting the public, within an area of exposure, where it is impossible or impractical to brief in advance all of the public that might possibly be within the area of exposure at the moment of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(13) Definition of referenced organizations and publications.

(A) ANSI--American National Standard Institute, 1430 Broadway, New York, New York 10018, Table I, Standard 253.1-1967.

(B) API--American Petroleum Institute, 300 Corrigan Tower Building, Dallas, Texas 75201, Publication API RP-49, Publication API RP-14E, Sections 1.7(c), 2.1(c) 4.7.

(C) ASTM--American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103, Standard D-2385-66.

(D) GPA--Gas Processors Association, 1812 First Place, Tulsa, Oklahoma 74120, Plant Operation Test Manual C-1, GPA Publication 2265-68.

(E) NACE--National Association of Corrosion Engineers, P.O. Box 1499, Houston, Texas 77001, Standard MR-01-75.

(F) DOT--Department of Transportation, Office of Pipeline Safety, 400 Seventh Street, S.W., Washington, D.C. 20590, Title 49, Code of Federal Regulations, Parts 192 and 195.

(G) OSHA--Occupational Safety and Health Administration, United States Department of Labor, 200 Constitution Avenue, NW, Washington D.C. 20270, Title 29, Code of Federal Regulations, Part 1910.145(c)(4)(i).

(H) RRC--Railroad Commission of Texas, Gas Utilities Division, P.O. Drawer 12967, Capitol Station, Austin, Texas 78711, Gas Utilities Dockets 446 and 183.

(c) General provisions.

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system.

(A) Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or other methods approved by the commission.

(B) Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

(2) For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations, or by other methods that have been approved by the commission.

(A) For determining the location of the 100 ppm radius of exposure: $x = [(1.589)\ (\text{mole fraction } H_2S)(Q)]$ to the power of (.6258).

(B) For determining the location of the 500 ppm radius of exposure: $x = [(0.4546)\ (\text{mole fraction } H_2S)(Q)]$ to the power of (.6258). Where x = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified in subparagraph (A) - (E) of this paragraph, as applicable.

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open-flow rate, or the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells, or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 pounds per square inch (psia) and 60 degrees Fahrenheit.

(E) For intentional releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system elements to be de-pressured.

(4) For the drilling of a well in an area where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) Storage tank provision: storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

(A) No determination of a radius of exposure shall be made for storage tanks as herein described.

(B) A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

(C) Fencing as a security measure is required when storage tanks are located inside the limits of a townsite or city, or where conditions cause the storage tanks to be exposed to the public.

(D) The warning and marker provision, paragraph (6)(A)(i), (ii), and (iv) of this subsection.

(E) The certificate of compliance provision, subsection (d)(1) of this section.

(6) All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

(A) Warning and marker provision.

(i) For above-ground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(ii) In populated areas such as cases of townsites and cities where the use of signs is not considered to be acceptable, then an alternative warning plan may be approved upon written request to the commission.

(iii) For buried lines subject to this section, the operator shall comply with the following.

(I) A marker sign shall be installed at public road crossings.

(II) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(III) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the effective date of this section shall be acceptable provided they indicate the existence of a potential hazard.

(iv) In satisfying the sign requirement of clause (i) of this subparagraph, the following will be acceptable.

(I) Sign of sufficient size to be readable at a reasonable distance from the facility.

(II) New signs constructed to satisfy this section shall use the language of "Caution" and "Poison Gas" with a black and yellow color contrast. Colors shall satisfy Table I of American National Standard Institute Standard Z53.1-1967. Signs installed to satisfy this section are to be compatible with the regulations of the federal Occupational Safety and Health Administration.

(III) Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

(B) Security provision.

(i) Unattended fixed surface facilities shall be protected from public access when located within 1/4 mile of a dwelling, place of business, hospital, school, church, government building, school bus stop, public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve opening, or other similar means. For the purpose of this provision, surface pipeline shall not be considered as a fixed surface facility.

(ii) For well sites, fencing as a security measure is required when a well is located inside the limits of a townsite or city, or where conditions cause the well to be exposed to the public.

(iii) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(C) Materials and equipment provision.

(i) For new construction or modification of facilities (including materials and equipment to be used in drilling and workover operations) completed or contemplated subsequent to the effective date of this section, the metal components shall be those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking. Other materials which are nonsusceptible to sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy the latest published, applicable industry standard, specifications, or recommended practices.

(ii) Other materials and equipment (including materials and equipment used in drilling and workover operations) which are not included within the provision of clause (i) of this subparagraph may be used for hydrogen sulfide service provided:

(I) such materials and equipment are proved, as the result of advancements in technology or as the result of control and knowledge of operating conditions (such as temperature and moisture content), to be suitable for the use intended and where such usage is technologically acceptable as good engineering practice; and

(II) the commission has approved the use of said materials and equipments for the specific uses after written application.

(iii) Existing facilities (including materials in present common usage for drilling and workover operations in hydrogen sulfide areas) which are in operation prior to the effective date of this section, and where there has been no failure of existing equipment attributed to sulfide stress cracking, shall satisfy the requirements of this section.

(iv) In the event of a failure of any element of an existing system as the result of hydrogen sulfide stress cracking, the compliance status of the system shall be determined by the commission after the operator has submitted to the commission a detailed written report on the failure.

(7) All operations subject to subsection (a) of this section shall be subject to the additional control and equipment safety provision, paragraph (8) of this subsection, and the contingency plan provision, paragraph (9) of this subsection, if any of the following conditions apply:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road;

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road;

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(8) Control and equipment safety provision. Operators subject to this provision shall install safety devices and maintain them in an operable condition or shall establish safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. For intentional releases of a potentially hazardous volume of hydrogen sulfide gas, the gas must be flared unless permission to vent is obtained from the commission or its delegate. Venting will be allowed only upon a showing that the venting will not pose an unreasonable risk of harm to the public.

(9) Contingency plan provision.

(A) All operators whose operations are subject to this provision shall develop a written contingency plan complete with all requirements before hydrogen sulfide operations are begun.

(B) The purpose of the contingency plan shall be to provide an organized plan of action for alerting and protecting the public prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(C) The contingency plan shall be activated prior to an intentional release, or immediately upon the detection of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(D) Conditions that might exist in each area of exposure shall be considered when preparing a contingency plan.

(E) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(F) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(G) The plan shall include a call list which shall include the following as they may be applicable:

(i) local supervisory personnel;

(ii) county sheriff;

(iii) Department of Public Safety;

(iv) city police;

(v) ambulance service;

(vi) hospital;

(vii) fire department;

(viii) doctors;

(ix) contractors for supplemental equipment;

(x) district Railroad Commission office;

(xi) the appropriate regional office of the Texas Commission on Environmental Quality or its successor agencies;

(xii) other public agencies.

(H) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(I) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the commission in accordance with subparagraph (L) of this paragraph.

(J) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(K) The plan shall include provisions for advance briefing of the public within an area of exposure. Such advance briefing shall include the following elements:

(i) the hazards and characteristics of hydrogen sulfide;

(ii) the necessity for an emergency action plan;

(iii) the possible sources of hydrogen sulfide within the area of exposure;

(iv) instructions for reporting a gas leak;

(v) the manner in which the public will be notified of an emergency;

(vi) steps to be taken in case of an emergency.

(L) In the event of a high density of population, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable. The reaction plan option must be approved by the commission.

(M) The plan shall include additional support information, if applicable, such as:

(i) location of evacuation routes;

(ii) location of safety and life support equipment;

(iii) location of hydrogen sulfide containing facilities;

(iv) location of nearby telephones and/or other means of communication; and

(v) special instructions for conditions at a particular installation such as local terrain and the effect of various weather conditions.

(N) The Railroad Commission District Office shall be notified as follows if the contingency plan is activated:

(i) 12 hours in advance of an intentional release or as soon as a decision is made to release if such decision could not reasonably have been made more than 12 hours prior to the release;

(ii) immediately in the case of an accidental release;

(iii) as soon as possible before or after an unplanned intentional release made in an emergency situation to prevent a possible uncontrolled release.

(O) The retention of the contingency plan shall be as follows.

(i) The plan shall be available for commission inspection at the location indicated on the certificate of compliance.

(ii) The plan shall be retained at the location which lends itself best to activation of the plan.

(P) In the event that, due to particular situations, a contingency plan cannot be developed consistent with the provisions of this paragraph, relating to the contingency plan, then the operator may develop an adjusted plan to fit the situation, and submit same with the certificate of compliance. Approval of the certificate of compliance so submitted will constitute approval of the contingency plan.

(Q) The plan shall be kept updated to insure its current applicability.

(10) Injection provision.

(A) Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this provision unless first approved by the commission after public hearing:

(i) where injection fluid is a gaseous mixture, or would be a gaseous mixture in the event of a release to the atmosphere, and where the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area except a public road; or, if the 500 ppm radius of exposure is in excess of 50 feet and includes any part of a public road; or if the 100 ppm radius of exposure is 3,000 feet or greater;

(ii) where the hydrogen sulfide content of the gas or gaseous mixture to be injected has been increased by a processing plant operation.

(B) Each project involving the injection of gas or gaseous mixtures containing hydrogen sulfide which does not require a public hearing prior to receiving commission approval specified in this provision shall nevertheless be subject to the other provisions of this section to the extent that such provisions are applicable to such project.

(11) In addition to any other requirements of this section, drilling and workover operations, and gasoline plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following.

(A) Protective breathing equipment shall be maintained in two or more locations at the site.

(B) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(C) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in concentrations that could be harmful shall be utilized at the site.

(12) Drilling provision. Drilling and workover operations where the 100 ppm radius of exposure includes a public area or is 3,000 feet or greater shall be subject to the following additional provisions.

(A) Protective breathing equipment shall be maintained at the well site and shall be sufficient to allow for well control operations.

(B) The operator shall provide a method of igniting the gas in the event of an uncontrollable emergency.

(C) The operator shall install a choke manifold, mud-gas separator, and flare line, and provide a suitable method for lighting the flare.

(D) Secondary remote control of blowout prevention and choke equipment to be located away from the rig floor at a safe distance from the wellhead.

(E) Drill stem testing of hydrogen sulfide zones is permitted only in daylight hours.

(F) The Railroad Commission district office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this provision.

(G) A certificate of compliance shall be required on

each well subject to this provision even if well is located on certificated lease.

(H) Full compliance with all the requirements of this provision must be satisfied before the well is drilled to a depth that is within 1,000 feet of the hydrogen sulfide zone. Alternate depths may be approved in advance by the appropriate commission district office.

(I) API Publication RP-49 is referenced as a suggested guideline for drilling and workover of wells subject to this provision.

(J) Blowout preventers and well control systems shall be pressure tested at or near compliance depth or at depth of nearest bit change prior to reaching compliance depth. The appropriate Railroad Commission district office must be notified at least four hours prior to the test.

(13) Training requirement provision.

(A) Each operator whose operations contain hydrogen sulfide in excess of 100 ppm shall train its employees working in the affected areas in hydrogen sulfide safety.

(B) Each operator shall require all service companies working in affected areas to utilize only those service company personnel who have been trained in accordance with the provisions of subparagraphs (C) and (D) of this paragraph. Written certification to the operator by the service company that only those service company personnel who have been trained in accordance with the training requirement provision will be utilized in affected areas complies with this provision. For this provision, service company shall mean any company actually performing work at well sites, gasoline plant sites, or on pipelines, where such work could allow the escape of hydrogen sulfide gas.

(C) The training of all personnel working in the affected areas shall include the following elements:

(i) hazards and characteristics of hydrogen sulfide;

(ii) safety precautions;

(iii) operation of safety equipment and life support system.

(D) On-site supervisory personnel shall be additionally trained in the following:

(i) effect of hydrogen sulfide on metal components in the system;

(ii) corrective action and shutdown procedures, and when drilling a well, blowout prevention, and well control procedures;

(iii) must have full knowledge of the requirements of the contingency plan, when such plan is required.

(E) Training schedules and course outlines shall be provided to the commission personnel upon request for the purpose of commission review to determine compliance with the provisions of subparagraphs (C) and (D) of this paragraph.

(14) Accident notification. Operators shall immediately notify the appropriate Railroad Commission District Office of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident.

(d) Reports required.

(1) Certificate of compliance provision. A certificate of compliance shall be submitted for operations subject to any provision of this section. The following shall apply to the certificate of compliance provision of the section.

(A) The certificate of compliance shall certify that operator has complied or will comply with applicable provisions of this section.

(B) The certificate of compliance shall be filed in triplicate in the commission district office where the operation is located.

(C) The certificate of compliance shall certify that existing operations subject to this section to be in compliance will be in compliance as specified in an attached schedule, or, for new or modified facilities, will be in compliance upon completion.

(D) An approved certificate of compliance will permit an operator to perform all activities described in the certificate without additional filing of approval; provided that, consistent with subsection (c)(12)(G) of this section, a certificate of compliance will be required on each well subject to the provisions of subsection (c)(12)(G) of this section.

(E) A new or amended certificate of compliance shall be required if there is a change in public exposure caused by public infringement of an existing radius of exposure resulting in a change in the applicable provisions of this section, not described by the existing certificate. The operator shall file the new or amended certificate within 30 days after such infringement.

(F) A new or amended certificate of compliance shall be required if there is modification of an existing operation or facility which increases the radius of exposure in a public area, or results in a change in the applicable provisions of this section not described by the existing certificate. The operator shall file the new or amended certificate at least 30 days prior to initiating the operation or construction.

(G) The operator shall file a certificate of compliance 30 days prior to commencement of a drilling or workover operation on wells where a certificate of compliance is required for that well by provisions of this section (wells drilled on noncertificated leases or wells with a 100 ppm radius of exposure greater than 3,000 feet).

(H) In case of extenuating circumstances, an operator may file a certificate of compliance with an attached written explanation for those cases where waiver of 30-day prior filing is requested. In such cases, the approval of the certificate of compliance will constitute authority to proceed.

(I) The certificate of compliance shall be prepared and executed by a party who, through training and experience, is qualified to make such certification.

(J) The certificate of compliance will be in effect until conditions are altered in a manner that would require amending the "certificate." The operator shall notify the commission within 30 days following cessation or abandonment of operations in a certificated area.

(K) The certificate of compliance required by the provisions of this order for an existing system are due in the district office as soon as is reasonably possible, and no later than September 1, 1976, and as applicable for new or modified operations.

(L) A certificate of compliance may cover a single operation or multiple operations located in an area, a field, or a group of fields within a commission district. The description of the type of operation as indicated on the form must be sufficiently complete to the degree that it is obvious what element of an operation is to be covered by the certificate. All Railroad Commission identification numbers for each element of the system must be shown on the certificate and must be identified as to the type of operation.

(M) Certificates are nontransferable, and a new operator of a system or any acquired element of a system or operation shall be required to certificate that operation. Operator of a certificated system shall notify the commission in writing when the system or any operating part has been transferred to another operator. An amended certificate shall be required should any change occur that would add or delete a Railroad Commission identification number covered by the certificate.

(N) Each operator shall maintain a current master list of all his operations for which a certificate of compliance is in effect and shall submit such list for inspection upon request by the commission.

(2) Completion report provision.

(A) The operator shall report on the initial completion report for new oil or gas wells the hydrogen sulfide concentrations of the wellhead gas for all wells where the hydrogen sulfide concentration is equal to or exceeds 100 ppm.

(B) The drilling of a well in an area which would require the submission of a certificate of compliance (Form H-9) shall have noted on the drilling application (Form W-1) that such certification has been filed.

(3) Releases of, and accidents related to, hydrogen sulfide. The operator shall furnish a written report to the district office within ten days of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident, whether it be from an accidental or intentional release.

(e) Exception provision. Any application for exception to the provisions of this section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

Source Note: The provisions of this §3.36 adopted January 1, 1976; amended to be effective September 1, 1976, 1 TexReg 1517; amended to be effective September 15, 1985, 10 TexReg 2069; amended to be effective April 7, 1995, 20 TexReg 2285; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.37 Statewide Spacing Rule

(a) Distance requirements.

(1) No well for oil, gas, or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than 467 feet to any property line, lease line, or subdivision line; provided the commission, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances than prescribed in this paragraph when the commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

(2) When an exception to this section is desired, application shall be made by filing the proper fee as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) and the appropriate form according to the instructions on the form, accompanied by a plat as described in subsection (c) of this section. A person acquainted with the facts pertinent to the application shall certify that all facts stated in it are true and within the knowledge of that person.

(A) When an exception to only the minimum lease-line spacing requirement is desired, the applicant shall file a list of the mailing addresses of all affected persons, who, for tracts closer to the well than the greater of one-half of the prescribed minimum between-well spacing distance or the minimum lease-line spacing distance, include:

(i) the designated operator;

(ii) all lessees of record for tracts that have no designated operator; and

(iii) all owners of record of unleased mineral interests.

(B) When an exception to the minimum between-well spacing requirement of this section is desired, the applicant is required to file the mailing addresses of those persons identified in subparagraph (A)(i)-(iii) of this paragraph for each adjacent tract and each tract nearer to the well than the greater of one-half the prescribed minimum between-well spacing distance or the minimum lease-line spacing.

(3) An exception may be granted pursuant to subsection (h)(2) of this section, or after a public hearing held after at least 10 days notice to all persons described in paragraph (2) of this subsection. At any such hearing, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to prevent the confiscation of property. For purposes of giving notice of an application for an exception, the commission will presume that every person described in paragraph (2) of this subsection will be affected by the application, unless the Oil and Gas Division director or the director's delegate determines they are unaffected. Such determination will be made only upon written request and a showing by the applicant that:

(A) competent, conclusive geological or engineering data indicate that no drainage of hydrocarbons from the particular tract(s) subject to the request will occur due to production from the applicant's proposed well; and

(B) notice to the particular operator(s), lessee(s) of record, or owner(s) of record of unleased mineral interest would be unduly burdensome or expensive.

(4) If, after diligent efforts, the applicant is unable to ascertain the name and address of one or more persons required by this subparagraph to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county where the well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(b) The distances mentioned in subsection (a) of this section are minimum distances to provide standard development on a pattern of one well to each 40 acres in areas where proration units have not been established.

(c) In filing an application for an exception to the distance requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the form a plat that:

(1) shows to scale the property on which the exception is sought; all other applied for, permitted, and completed oil, gas, or oil and gas wells in the same field and reservoir on said property; and all adjoining surrounding properties and completed wells in the same field and reservoir within the prescribed minimum between-well spacing distance of the applicant's well;

(b) Assignment of allowables for wells under statewide rules.

(1) All wells completed in fields operating under statewide rules which were assigned the 20-acre yardstick allowable prior to the adoption of the new spacing rule on October 1, 1962, will be continued at the same allowable rate unless, after notice and hearing, special rules or other special orders are adopted that would provide for a higher producing rate. Any new well completed in such a reservoir will be given the same allowable rate as is assigned the other wells even though it has been drilled as a regular location under the new statewide spacing rule and density rule.

(2) All wells completed in fields operating under statewide rules that are presently on discovery status or have had discovery status terminated subsequent to the adoption of the new state spacing rule on October 1, 1962, will be given the 40-acre yardstick allowable, until such time as a change is ordered by the commission.

(c) Production of marginal wells.

(1) To artificially curtail the production of any "marginal well" below the marginal limit prior to its ultimate plugging and abandonment is hereby declared to be waste, and no rule or order of the Railroad Commission of Texas, or other constituted legal authority shall be entered requiring restriction of the production of any "marginal well" as defined in this chapter.

(2) Application of paragraph (1) of this subsection shall be confined to unrestricted operating conditions which accord with established operating rules of the commission, and shall be subject to all operating conditions designed to prevent waste imposed by the commission, which conditions apply to all wells alike. (Reference Order Number 20-54,115, effective January 1, 1965.)

Source Note: The provisions of this §3.45 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 1, 2016, 41 TexReg 785.

§3.46 Fluid Injection into Productive Reservoirs

(a) Permit required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of application.

(1) Application.

(A) An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form.

(B) The applicant shall file the freshwater injection data form if fresh water is to be injected.

(C) The applicant for a disposal well permit under this section shall include with the permit application a printed copy or screenshot showing the results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

(D) The commission may require an applicant for a disposal well permit under this section to provide the commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and opportunity for hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.

(3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.

(4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(5) Protested applications:

(A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(B) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(d) Subsequent commission action.

(1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(A) a material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone;

(F) for a disposal well permit under this section, injection is likely to be or determined to be contributing to seismic activity; or

(G) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.

(3) Voluntary permit suspension.

(A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.

(B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.

(C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1) - (3) of this section shall not apply.

(E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.

(e) Area of Review.

(1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(A) the area affected by pressure increases resulting from injection operations;

(B) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(C) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:

(A) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(B) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:

(i) the manager of each underground water conservation district in which the variance would apply, if any;

(ii) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(iii) the county clerk of each county in which the variance would apply; and

(iv) any other person or persons that the commission or its delegate determines should receive notice of the application.

(5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.

(f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.

(g) Special equipment.

(1) Tubing and packer. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

(2) Pressure valve. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(3) Exceptions. The commission or its delegate may grant an exception to any provision of this paragraph upon proof of good cause. If the commission or its delegate denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(h) Well record. Within 30 days after the completion or conversion of an injection well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(i) Monitoring and reporting.

(1) The operator shall monitor the injection pressure and injection rate of each injection well on at least a monthly basis, or on a more frequent basis for a disposal well permitted under this section as required by the commission under conditions described in subsection (b)(1)(D) of this section.

(2) The results of the monitoring shall be reported annually, or on a more frequent basis for a disposal well permitted under this section as required by the commission under conditions described in subsection (b)(1)(D) of this section, to the commission on the prescribed form.

(3) All monitoring records shall be retained by the operator for at least five years.

(4) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(j) Testing.

(1) Purpose. The mechanical integrity of an injection well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under paragraph (5) of this subsection.

(2) Applicability. Mechanical integrity of each injection well shall be demonstrated in accordance with provisions of paragraphs (4) and (5) of this subsection prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in paragraph (3) of this subsection.

(3) Frequency.

(A) Each injection well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(B) In addition to testing required under subparagraph (A), each injection well shall be tested for mechanical integrity after every workover of the well.

(C) An injection well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the injection permit.

(D) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in subparagraph (A) and subparagraph (B) of this paragraph. Such testing schedule shall not apply to an injection well for which an injection well permit has been issued but the well has not been drilled or converted to injection.

(4) Pressure tests.

(A) Test pressure.

(i) The test pressure for wells equipped to inject through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(ii) The test pressure for wells that are permitted for injection through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(B) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in subparagraph (A) of this paragraph prior to commencement of the test.

(C) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(D) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(E) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for injection through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(F) Test fluid.

(i) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes use of a different test fluid for good cause.

(ii) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(G) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(i) the degree of pressure change during the test, if any;

(ii) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(iii) whether circumstances surrounding the administration of the test make the test inconclusive.

(5) Alternative testing methods.

(A) As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by subsection (i) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under paragraph (3) of this subsection at least once every ten years after January 1, 1990.

(B) The commission or its delegate grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(6) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(7) A complete record of all tests shall be filed in duplicate in the district office within 30 days after the testing.

(8) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(k) Area Permits. A person may apply for an area permit that authorizes injection into new or converted wells located within the area specified in the area permit. For purposes of this subsection, the term "permit area" shall mean the area covered or proposed to be covered by an area permit. Except as specifically provided in this subsection, the provisions of subsections (a) - (j) of this section shall apply in the case of an area permit and all injection wells converted, completed, operated, or maintained in accordance with that permit. Except as otherwise specified in the area permit, once an area permit has been issued, the operator may apply to operate individual wells within the permit area as injection wells as specified in paragraph (3) of this subsection.

(1) An application for an area permit must be accompanied by an application for at least one injection well. The applicant must:

(A) identify the maximum number of injection wells that will be operated within the permit area;

(B) identify the depth(s) of usable-quality water within the permit area, as determined by the Groundwater Advisory Unit of the Oil and Gas Division;

(C) for each existing well in the permit area that may be converted to injection under the area permit, provide a wellbore diagram that specifies the casing and liner sizes and depths, packer setting depth, types and volumes of cement, and the cement tops for the well. A single wellbore diagram may be submitted for multiple wells that have the same configuration, provided that each well with that type of configuration is identified on the wellbore diagram and the diagram identifies the deepest cement top for each string of casing among all the wells covered by that diagram.

(D) provide a wellbore diagram(s) showing the type(s) of completion(s) that will be used for injection wells drilled after the date the application for the area permit is filed, including casing and liner sizes and depths and a statement indicating that such wells will be cemented in accordance with the cementing requirements of §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) (Statewide Rule 13);

(E) identify the type or types of fluids that are proposed to be injected into any well within the permit area;

(F) identify the depths from top to bottom of the injection interval throughout the permit area;

(G) specify the maximum surface injection pressure for any well in the permit area covered by the area permit;

(H) specify the maximum amount of fluid that will be injected daily into any individual well within the permit area as well as the maximum cumulative amount of fluid that will be injected daily in the permit area;

(I) in lieu of the area-of-review required under subsection (e) of this section and subject to the area-of-review variance provisions of subsection (e) of this section, review the data of public record for wells that penetrate the proposed injection interval within the permit area and the area 1/4 mile beyond the outer boundary of the permit area to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the injection interval into freshwater strata. The applicant shall identify in the application the wells which appear from the review of such public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has knowledge. The applicant shall also identify in the application the date of plugging of each abandoned well within the permit area and the area 1/4 mile beyond the outer boundary of the permit area; and

(J) furnish a map showing the location of each existing well that may be converted to injection under the area permit and the location of each well that the operator intends, at the time of application, to drill within the permit area for use for injection. The map shall be keyed to identify the configuration of all such wells as described in subparagraphs (C) and (D) of this paragraph.

(2) In lieu of the notice required under subsection (c)(1) of this section, notice of an area permit shall be given by providing a copy of the area permit application to each surface owner of record within the permit area; each commission-designated operator of a well located within one-half mile of the permit area; the county clerk of each county in which all or part of the permit area is located; and the city clerk or other appropriate city official of any incorporated city which is located wholly or partially within the permit area, on or before the date the application is mailed to or filed with the commission. Notice of an application for an area permit shall also be given in accordance with the requirements of subsection (c)(2). If, in connection with a particular application, the commission or its delegate determines that another class of persons, such as adjacent surface owners or an appropriate underground water conservation district, should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class.

(3) Once an area permit has been issued and except as otherwise provided in the permit, no notice shall be required when an application for an individual injection well permit for any well covered by the area permit is filed.

(4) Prior to commencement of injection operations in any well within the permit area, the operator shall file an application for an individual well permit with the commission in Austin. The individual well permit application shall include the following:

(A) the well identification and, for a new well, a location plat;

(B) the location of any well drilled within 1/4 mile of the injection well after the date of application for the area permit and the status of any well located within 1/4 mile of the injection well that has been abandoned since the date the area permit was issued, including the plugging date if such well has been plugged;

(C) a description of the well configuration, including casing and liner sizes and setting depths, the type and amount of cement used to cement each casing string, depth of cement tops, and tubing and packer setting depths;

(D) an application fee in the amount of $100 per well; and

(E) any other information required by the area permit.

(5) An individual well permit may be issued by the commission or its delegate in writing or, if no objection to the application is made by the commission or its delegate within 20 days of receipt of the application, the individual well permit shall be deemed issued.

(6) All individual injection wells covered by an area permit must be permitted in accordance with the requirements of this subsection and converted or completed, operated, maintained, and plugged in accordance with the requirements of this section and the area permit.

(l) Gas storage operations. Storage of gas in productive or depleted reservoirs shall be subject to the provisions of §3.96 of this title (relating to Underground Storage of Gas in Productive or Depleted Reservoirs).

(m) Plugging. Injection wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(n) Penalties.

(1) Violations of this section may subject the operator to penalties and remedies specified in Title 3 of the Natural Resources Code and any other statutes administered by the commission.

(2) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline

Connection; Cancellation of Certificate of Compliance; Severance) for violation of this section.

Source Note: The provisions of this §3.46 adopted to be effective January 1, 1976; amended to be effective April 1, 1982, 7 TexReg 655; amended to be effective January 1, 1994, 18 TexReg 8871; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective April 7, 1998, 23 TexReg 3432; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective November 17, 2014, 39 TexReg 8988.

§3.47 Allowable Transfers for Saltwater Injection Wells

An allowable transfer will not be authorized for a well converted from oil production to saltwater disposal; however, an operator may make application to use the well for dual-purpose waterflood and saltwater disposal if injection is into an oil productive zone, and it is shown that the water injection will not injure the reservoir but will probably be of benefit to the reservoir as a secondary recovery program even though the beneficial effect of the water injection cannot be readily determined.

Source Note: The provisions of this §3.47 adopted to be effective January 1, 1976.

§3.48 Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Capacity oil allowable--The allowable assigned from time to time by the director of the Oil and Gas Division or the director's delegate to an oil lease or unit engaged in a secondary or tertiary recovery program, that is consistent with the ability of the lease or unit to produce and that will prevent the occurrence of overproduced status for the lease or unit. Capacity oil allowables encompass and supercede what the Railroad Commission formerly designated as waterflood allowables.

(2) Offsetting operators and unleased mineral interest owners affected by the application--All offsetting operators and unleased mineral interest owners to the lease or unit except for those offsetting operators and unleased mineral owners the director of the Oil and Gas Division or the director's delegate determines to be unaffected by the application.

(b) Application. The director of the Oil and Gas Division or the director's delegate may grant a capacity oil allowable for a lease or unit, to the operator of a secondary or tertiary recovery project, when evidence of production increase in response to the secondary or tertiary recovery project is noted. The operator's application for a capacity oil allowable shall consist of:

(1) a written request that shall contain a statement indicating that all offsetting operators and unleased mineral interest owners affected by the application have been sent a copy of the complete application, and a list of such offsetting operators and unleased mineral interest owners indicating the date that notification was sent;

(2) evidence of the operator's participation in the subject secondary or tertiary recovery project;

(3) a plat indicating all producing wells and injection wells on the lease or unit and all offsetting operators and unleased mineral interest owners to the lease or unit;

(4) if available, signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application; and

(5) a production graph illustrating both increased production and volumes of water or other substances used in the secondary or tertiary recovery project that have been injected on the lease or unit since initiation of the secondary or tertiary recovery project.

(c) Notice and hearing. If the operator does not submit signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, there shall be a minimum of 21 days notice of the application for a capacity oil allowable; provided that, if the operator requests a hearing to consider the application, such hearing shall be held only after at least 10 days notice. If the director of the Oil and Gas Division or the director's delegate declines to approve the initial application, or if a protest is received by the Oil and Gas Division within the prescribed notice period, the operator may request a hearing to show that the capacity oil allowable is necessary either to prevent waste or to protect correlative rights. Any hearing held pursuant to this section shall be held only after at least 10 days notice. If the operator submits signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, or if no protest is received by the Oil and Gas Division within the 21-day notice period, or if no protestant appears at a hearing to consider an application for a capacity oil allowable, the capacity oil allowable may be granted administratively by the director of the Oil and Gas Division or the director's delegate if the application establishes that the capacity oil allowable is necessary to ensure maximum recovery from the secondary or tertiary recovery project.

(d) Temporary basis. A capacity oil allowable may be granted on a temporary basis by the director of the Oil and Gas Division or the director's delegate upon receipt of a complete application indicating that an immediate allowable increase is necessary to ensure maximum recovery from the secondary or tertiary recovery project. If a hearing is held to consider the application, any capacity oil allowable previously granted on a temporary basis under this section will remain in effect until a signed order of the Railroad Commission is issued in the matter. If the commission order denies the application, or if an applicant fails to request a hearing to consider a protested application, additional production resulting from the are removed, and shall retain a copy on file for two years.

(C) The operator of the reclamation plant or other authorized person shall leave a copy of the manifest in the vehicle transporting the material.

(2) The operator of a reclamation plant or other authorized person shall conduct a shakeout (centrifuge) test on all tank bottoms or other hydrocarbon wastes upon removal from any producing lease tank, pipeline storage tank, or other production facility, to determine the crude oil content and lease condensate thereof.

(3) The shakeout test shall be conducted in accordance with the most current American Petroleum Institute or American Society for Testing Materials method.

(e) Reporting of reclaimed crude oil or lease condensate on commission required report.

(1) For wastes taken to a reclamation plant the following provisions shall apply.

(A) The net crude oil content or lease condensate from a producing lease's tank bottom as indicated by the shakeout test shall be used to calculate the amount of oil to be reported as a disposition on the monthly production report. The net amount of crude oil or lease condensate from tank bottoms taken from a pipeline facility shall be reported as a delivery on the monthly transporter report.

(B) For other hydrocarbon wastes, the net crude oil content or lease condensate of the wastes removed from a tank, treater, firewall, pit, or other container at an active facility, including a pipeline facility, shall also be reported as a disposition or delivery from the facility.

(2) The net crude oil content or lease condensate of any tank bottoms or other hydrocarbon wastes removed from an active facility, including a pipeline facility, and disposed of on-site or delivered to a site other than a reclamation plant shall also be reported as a delivery or disposition from the facility. All such disposal shall be in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). Operators may be required to obtain a minor permit for such disposal using procedures set out in §3.8(d) and (g) of this title (relating to Water Protection). Prior to approval of the minor permit, the commission may require an analysis of the disposable material to be performed.

(f) General provisions applicable to materials taken to a reclamation plant.

(1) The removal of tank bottoms or other hydrocarbon wastes from any facility for which monthly reports are not filed with the commission must be authorized in writing by the commission prior to such removal. A written request for such authorization must be sent to the commission office in Austin, and must detail the location, description, estimated volume, and specific origin of the material to be removed, as well as the name of the reclaimer and intended destination of the material. If the authorization is denied, the applicant may request a hearing.

(2) The receipt of any tank bottoms or other hydrocarbon wastes from outside the State of Texas must be authorized in writing by the commission prior to such receipt. However, written approval is not required if another entity will indicate, in the appropriate monthly report, a corresponding delivery of the same material. If the request is denied, the applicant may request a hearing.

(3) The receipt of any waste materials other than tank bottoms or other hydrocarbon wastes must be authorized in writing by the commission prior to such receipt. The commission may require the reclamation plant operator to submit an analysis of such waste materials prior to a determination of whether to authorize such receipt. If the request is denied, the applicant may request a hearing.

(4) The operator of a reclamation plant shall file a report on the appropriate commission form for each reclamation plant facility by the 15th day of each calendar month, covering the facility's activities for the previous month. The operator of a reclamation plant shall file a copy of the monthly report in the district office of any district in which the operator made receipts or deliveries for the month covered by the report.

(5) All wastes generated by reclaiming operations shall be disposed of in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(g) Commission review of administrative actions. Administrative actions performed by the director or commission staff pursuant to this rule are subject to review by the commissioners.

(h) Policy. The provisions of this rule shall be administered so as to prevent waste and protect correlative rights.

Source Note: The provisions of this §3.57 adopted to be effective April 11, 1990, 15 TexReg 1693; amended to be effective June 1, 1998, 23 TexReg 5656; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271.

§3.58 Certificate of Compliance and Transportation Authority; Operator Reports

(a) Certificate of Compliance and transportation authority.

(1) Each operator who seeks to operate any well subject to the jurisdiction of the Commission shall file with the commission's Austin office a commission form P-4 (certificate of compliance and transportation authority) for each property on which the wells are located certifying that the operator has complied with Texas Natural

Resources Code, Title 3; Texas Water Code, §26.131; and Texas Water Code, Chapter 27, and orders, rules, and regulations of the commission pursuant to Texas Natural Resources Code, Title 3; Texas Water Code, §26.131; and Texas Water Code, Chapter 27, in respect to the property. The Commission form P-4 establishes the operator of an oil lease, gas well, or other well; certifies responsibility for regulatory compliance, including plugging wells in accordance with §3.14 of this title (relating to plugging); and identifies gatherers, purchasers, and purchasers' commission-assigned system codes authorized for each well or lease. Operators shall file form P-4 for new oil leases, gas wells, or other wells; recompletions; reclassifications of wells from oil to gas or gas to oil; consolidation, unitization or subdivision of oil leases; or change of gatherer, gas purchaser, gas purchaser system code, operator, field name or lease name. When an operator files a form P-4, the oil and gas division shall review the form for completeness and accuracy. The Commission may require an operator who files a form P-4 for the purpose of changing the designation of an operator for a lease or well to provide to the Commission evidence that the transferee has the right to operate the lease or well. Except as otherwise authorized by the Commission, a transporter (whether the operator or someone else) shall not transport the oil, gas, or geothermal resources from such property until the Commission has approved the certificate of compliance and transportation authority. No certificate of compliance designating or changing the designation of an operator will be approved that is signed, either as transferor or transferee, by a non-employee agent of the organization unless the organization has filed with the commission, on its organization report, the name of the non-employee agent it has authorized to sign such certificates of compliance on its behalf.

(2) An approved certificate of compliance and transportation authority shall bind the operator until another operator files a subsequent certificate and the Commission has approved the subsequent certificate and transferred the property on commission records to the subsequent operator.

(3) The appropriate district office or the Austin office may grant temporary authority for an operator to use a transporter not authorized for a particular property in order to take care of production and prevent waste. The operator shall secure such temporary authority in writing from the appropriate district office or the Austin office before the oil or condensate is moved. In an emergency situation the operator may secure such temporary authority verbally but shall notify the district office in writing within 10 days after the oil or condensate is moved. An emergency situation exists when oil or condensate must be moved off a lease because it poses an imminent threat to the public health and safety, or when the threat of waste is imminent. The operator shall also furnish copies of such authorization or notification to the regular transporter and to the temporary transporter.

(4) If an applicant wishes to assume operator status for a property, but is unable to obtain the signature of the previous operator on the certificate of compliance and transportation authority, the applicant shall file with the oil and gas division in Austin a completed form P-4 signed by a designated officer or agent of the applicant, along with an explanatory letter and legal documentation of the applicant's right to operate the property. Prior to approval of such an application, the office of the general counsel will notify the last known operator of record, if such operator's address is available, affording such operator an opportunity to protest.

(b) Monthly production report (oil, natural gas and geothermal resources). For each calendar month, each operator who is a producer of crude oil, natural gas or geothermal resources shall file with the commission a report for each of the operator's producing properties. Operators shall file such reports on commission Form PR, Monthly Production Report, or commission Form GT-2 (producer's monthly report of geothermal wells). These commission forms report monthly production and disposition of oil and condensate, and casinghead gas and gas well gas (Form PR) and geothermal resources (Form GT-2). On or before the last day of the month subsequent to the period of the report, the operator shall file the original form with the Austin office, and one copy with the transporter taking the oil, gas or geothermal resources from the property if requested by the transporter.

(c) Recovered load oil.

(1) The operator of each lease from which load oil is recovered shall file the original and one copy of commission form P-3 (authority to transport recovered load or frac oil) with the district office, and another copy with the transporter prior to running the load oil. Form P-3 requires a producer to report the quantity of recovered load or frac oil to be transported from a particular lease and to identify the transporter. The form P-3 (authority to transport recovered load or frac oil) filed by the operator shall be the authority for the transporter to run the quantity of recovered load or frac oil stated in the form.

(2) The provisions of this subsection apply only to oil that has been obtained from a source other than the lease on which it is used. "Recovered load oil or frac oil," as that term is used herein, is any oil or liquid hydrocarbons used in any operation in an oil or gas well, and which has been recovered as a merchantable product.

(d) Subdivision and consolidation of oil leases.

(1) An operator seeking to subdivide or consolidate existing oil leases shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). Form P-6 identifies the leases to be subdivided or consolidated as well as the resulting leases. Two plats shall be filed with form P-6, one showing the boundaries of the lease(s) before and one showing the boundaries of the lease(s) after the subdivision or consolidation.

(2) An operator seeking to subdivide an existing oil lease that it operates or to assume operatorship of fewer than all of the wells on an oil lease shall file and obtain

approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to subdivide an oil lease may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules.

(3) An operator seeking to consolidate two or more existing oil leases that it operates shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to consolidate two or more oil leases may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules and:

(A) the mineral and royalty ownership of the leases proposed for consolidation is identical in all respects;

(B) the operator has obtained a surface commingling exception permit pursuant to §3.26 of this title (relating to separating devices, tanks, and surface commingling of oil) that authorizes commingling of production from all of the leases proposed for consolidation; or

(C) the operator has filed and obtained approval of a valid commission form P-12 (certificate of pooling authority) authorizing pooling of all of the leases proposed for consolidation.

Source Note: The provisions of this §3.58 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective May 12, 2002, 27 TexReg 3756; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective November 26, 2007, 32 TexReg 8452.

§3.59 Oil and Gas Transporter's Reports

(a) General. The commission may, from time to time, require oil and gas pipeline companies to make reports to the commission showing wells connected with their lines during any month, the amount of production taken therefrom, names of parties from whom oil and gas are purchased, and the amount of oil or gas purchased therefrom.

(b) Daily report. The commission may, in case of overproduction or for any other reason which it deems urgent, require oil and gas pipe line companies to furnish daily reports of the amount of oil or gas purchased or taken from different wells or parties.

(c) Weekly stock report. Rescinded by Order Number 20-57,970, effective 11-16-67.

(d) Monthly transportation and storage report.

(1) Each gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall file with the commission on or before the last day of each calendar month a report showing the required information concerning the transportation operations of such gatherer, transporter, or storer for the next preceding month. Such form is incorporated in and made a part of this section.

(2) The original of the report, covering all of the operations of the gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall be filed in the Austin office of the commission. One copy of the report shall be filed in each district office in which the gatherer, transporter, storer, and/or handler of crude oil or products, or both, operates, but may include only the information pertaining to the operations in that district in which it is filed.

(3) The written instructions appearing on said form are incorporated in and made a part of this section, and all of the data and information on the form shall be reported and arranged on the form as required by the form.

(4) No gatherer, transporter, storer, and/or handler of crude oil shall remove crude oil from any property unless such property is identified by a sign posted in compliance with §3.3(3) of this title (relating to Identification of Properties, Wells, and Tanks).

(5) The provisions of this section shall not apply to the operator of any refinery, processing plant, blending plant, or treating plant to which §3.60 of this title (relating to Refinery Reports) applies if the operator has filed the required form.

(e) Annual report.

(1) Each common carrier pipeline shall make and file with the commission, at its Austin office, an annual report for each calendar year. The report must show the names of the officers, directors, and stockholders, and the residence of each; the amount of capital stock and bonded indebtedness outstanding; the results of financial operations; the sources of revenue; and the expenditures, assets and liabilities, and statistical data of oil transported; and such other information as may be deemed pertinent by the commission concerning the carrier's transactions in the performance of services under its charter provisions relative to the transportation of crude petroleum in the State of Texas.

(2) The annual report must be made to the commission on the form prescribed and furnished by the commission; and must be returned complete, under oath, within 30 days after the receipt of the forms from the commission.

(3) For all purposes applicable under these rules and regulations the "Classification of Investment for Pipe Lines, Pipe Line Operating Revenues, and Pipe Line Operating Expenses" prescribed by the Interstate Commerce Commission and effective on January 1, 1915, is adopted and made a part of these rules for the use of all common carrier pipelines subject to the provisions of that

(b) As provided in subsections (e) and (f) of this section, the surface owners of a parcel of land may restrict use of the surface by the possessory mineral owners if the tract is a qualified subdivision and if a plat of the subdivision has been approved by the Railroad Commission after notice and hearing and filed with the clerk of the county in which the qualified subdivision is to be located.

(c) An application for a hearing under this section must be made in writing and mailed or delivered to the director of the Oil and Gas Division. The application must include:

(1) a jurisdictional statement setting out the facts stated in subsection (a)(4)(A) and (B) of this section;

(2) a statement that the applicant has authority to represent and represents all surface owners of land contained in the proposed qualified subdivision;

(3) the names and addresses of all owners of possessory mineral interests and all mineral lessors of land contained in the proposed qualified subdivision;

(4) a plat of the proposed subdivision showing each proposed 80-acre tract with its operations site, road easements, and pipeline easements and a legible copy thereof no larger than 8 1/2 inches by 11 inches;

(5) a concise description of mineral development in the area, including the number of oil and/or gas wells within 2.5 miles of the boundary of the proposed qualified subdivision and the depths at which each well is completed;

(6) a list of all the Railroad Commission designated oil and/or gas fields, if any, which underlie the proposed qualified subdivision; including the spacing and density requirements. If no Railroad Commission designated fields underlie the qualified subdivision, the application should so state.

(d) The Railroad Commission shall, on proper notice to the applicant and owners of possessory mineral interests and mineral lessors of land contained in the proposed qualified subdivision, hold a hearing on the application to determine the adequacy of the number and location of operations sites and road and pipeline easements. At the hearing on the application, evidence may be presented by the applicant and the owners of possessory mineral interests and mineral lessors. The applicant must carry the burden of proof. After considering the evidence, the commission may approve, reject, or amend the application to ensure that the mineral resources of the subdivision may be fully and effectively developed.

(e) An owner of a possessory mineral interest within a Railroad Commission approved qualified subdivision may use only the surface contained in designated operations sites for exploration, development, and production of minerals and only the designated easements as necessary to adequately use the operations sites.

(f) The owner of the possessory mineral interest may drill wells or extend well bores from an operations site or from a site outside of the qualified subdivision to bottomhole locations vertically beneath the surface of parts of the qualified subdivision other than the operation sites. Such drilling is subject to other applicable commission rules and regulations, and is permissible only to the extent that the operations do not unreasonably interfere with the use of the surface of the qualified subdivision outside the operations site.

(g) Subsections (e) and (f) of this section cease to apply to a subdivision if, by the third anniversary of the date on which the order of the commission becomes final:

(1) the surface owner has not commenced actual construction of roads or utilities within the qualified subdivision; and

(2) a lot within the qualified subdivision has not been sold to a third party.

(h) All or any portion of a qualified subdivision may be amended, replatted, or abandoned by the surface owner. An amendment or replat, however, may not alter, diminish, or impair the usefulness of an operations site or appurtenant road or pipeline easement unless the amendment or replat is approved by the commission. Railroad Commission approval of a replat or amendment may be administratively granted by the director of the Oil and Gas Division, or his delegate, upon submission of items required in subsection (c) of this section and after notice and opportunity for hearing has been afforded to all possessory mineral interest owners and mineral lessors of land contained within the original and/or replatted or amended qualified subdivision.

Source Note: The provisions of this §3.76 adopted to be effective July 10, 2000, 25 TexReg 6487.

§3.78 Fees and Financial Security Requirements

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Violation--Noncompliance with a Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(2) Outstanding violation--A violation for which:

(A) either:

(i) a Commission order finding a violation has been entered and all appeals have been exhausted; or

(ii) an agreed order between the Commission and the organization relating to a violation has been entered; and

(B) one or more of the following conditions still exist:

(i) the conditions that constituted the violation have not been corrected;

(ii) all administrative, civil, and criminal penalties, if any, relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid; or

(iii) all reimbursements of any costs and expenses assessed by the Commission relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid.

(3) Commercial facility--A facility whose owner or operator receives compensation from others for the storage, reclamation, treatment, or disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the facility and whose primary business purpose is to provide these services for compensation if:

(A) the facility is permitted under §3.8 of this title (relating to Water Protection);

(B) the facility is permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials);

(C) the facility is permitted under §3.9 of this title (relating to Disposal Wells) and a collecting pit permitted under §3.8 is located at the facility; or

(D) the facility is permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) and a collecting pit permitted under §3.8 is located at the facility.

(4) Financial security--An individual performance bond, blanket performance bond, letter of credit, or cash deposit filed with the Commission.

(5) Bay well--Any well under the jurisdiction of the Commission for which the surface location is either:

(A) located in or on a lake, river, stream, canal, estuary, bayou, or other inland navigable waters of the state and which requires plugging by means other than conventional land-based methods, including, but not limited to, use of a barge, use of a boat, dredging, or building a causeway or other access road to bring in the necessary equipment to plug the well; or,

(B) located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of the Gulf of Mexico.

(6) Land well--Any well subject to Commission jurisdiction for which the surface location is not in or on inland or coastal waters.

(7) Offshore well--Any well subject to Commission jurisdiction for which the surface location is on state lands in or on the Gulf of Mexico, that is not a bay well.

(8) Officers and owners--Any persons owning or controlling an organization including officers, directors, general partners, sole proprietors, owners of more than 25% ownership interest, any trustee of an organization, and any person determined by a final judgment or final administrative order to have exercised control over the organization.

(9) Letter of credit--An irrevocable letter of credit issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party bank authorized under state or federal law to do business in Texas; and

(C) renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by the Commission or its authorized delegate.

(10) Bond--A surety instrument issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party corporate surety authorized under state law to issue surety bonds in Texas; and

(C) renewed and continued in effect until the conditions of the bond have been met or its release is approved by the Commission or its authorized delegate.

(11) Well-specific plugging insurance policy--An insurance policy that:

(A) is approved by the Texas Department of Insurance;

(B) is issued by an insurer authorized under state law to issue a well-specific plugging insurance policy in Texas;

(C) names the Commission as the owner and contingent beneficiary of the policy;

(D) names a primary beneficiary who agrees to plug the specified well bore;

(E) is fully prepaid and cannot be canceled or surrendered;

(F) provides that the policy continues in effect until the well bore has been plugged as required by the Commission;

(G) provides that benefits will be paid when, but not before, the specified well bore has been plugged; and

(II) provides that benefits that will equal or exceed:

(i) $2 per foot for each foot of well depth for land wells;

(ii) $60,000 for bay wells; or

(iii) $100,000 for offshore wells.

(12) Director--The director of the Commission's Oil and Gas Division or the director's delegate.

(13) Escrow funds--Funds deposited with the Commission as part of an application for a plugging extension for an inactive land well.

(14) Groundwater protection determination letter--A letter of determination stating the total depth of surface casing required for a well in accordance with Texas Natural Resources Code, §91.011.

(b) Filing fees. The following filing fees are required to be paid to the Railroad Commission.

(1) With each application or materially amended application for a permit to drill, deepen, plug back, or reenter a well, the applicant shall submit to the Commission a nonrefundable fee of:

(A) $200 if the proposed total depth of the well is 2,000 feet or less;

(B) $225 if the proposed total depth of the well is greater than 2,000 feet but less than or equal to 4,000 feet;

(C) $250 if the proposed total depth of the well is greater than 4,000 feet but less than or equal to 9,000 feet; or

(D) $300 if the proposed total depth of the well is greater than 9,000 feet.

(2) An application for a permit to drill, deepen, plug back, or reenter a well will be considered materially amended if the amendment is made for a purpose other than:

(A) to add omitted required information;

(B) to correct typographical errors; or

(C) to correct clerical errors.

(3) An applicant shall submit an additional nonrefundable fee of $150 when requesting that the Commission expedite the application for a permit to drill, deepen, plug back, or reenter a well.

(4) With each individual application for an exception to any rule or rules in this chapter, the applicant shall submit to the Commission a nonrefundable fee of $150, except as provided in paragraph (5) of this subsection.

(5) With each application for an exception to any rule or rules in this chapter that includes an exception to §3.37 of this title (relating to Statewide Spacing Rule) (Statewide Rule 37) or §3.38 of this title (relating to Well Densities) (Statewide Rule 38), the applicant shall submit a nonrefundable fee of $200.

(6) With each application for an oil and gas waste disposal well permit, the applicant shall submit to the Commission a nonrefundable fee of $100 per well.

(7) With each application for a fluid injection well permit, the applicant shall submit to the Commission a nonrefundable fee of $200 per well. Fluid injection well means any well used to inject fluid or gas into the ground in connection with the exploration or production of oil or gas other than an oil and gas waste disposal well.

(8) With each application for a permit to discharge to surface water other than a permit for a discharge that meets national pollutant discharge elimination system (NPDES) requirements for agricultural or wildlife use, the applicant shall submit to the Commission a nonrefundable fee of $300.

(9) If a certificate of compliance for an oil lease or gas well has been canceled for violation of one or more Commission rules, the operator shall submit to the Commission a nonrefundable fee of $300 for each severance or seal order issued for the well or lease before the Commission may reissue the certificate pursuant to §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) (Statewide Rule 58).

(10) With each application for issuance, renewal, or material amendment of an oil and gas waste hauler's permit, the applicant shall submit to the Commission a nonrefundable fee of $100.

(11) With each Natural Gas Policy Act (15 United States Code §§3301-3432) application, the applicant shall submit to the Commission a nonrefundable fee of $150.

(12) Hazardous waste generation fee. A person who generates hazardous oil and gas waste, as that term is defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), shall pay to the Commission the fees specified in §3.98(z).

(13) Inactive well extension fee.

(A) For each well identified by an operator in an application for a plugging extension based on the filing of an abeyance of plugging report on Commission Form W-3X, the operator must pay to the Commission a non-refundable fee of $100.

(B) For each well identified by an operator in an application for a plugging extension based on the filing of a fluid level or hydraulic pressure test that is not otherwise required to be filed by the Commission, the operator must pay to the Commission a non-refundable fee of $50.

(14) Groundwater protection determination letters.

(A) With each individual request for a groundwater protection determination letter, the applicant shall submit to the Commission a nonrefundable fee of $100.

(B) With each individual application for an expedited letter of determination stating the total depth of surface casing required for a well in accordance with Texas Natural Resources Code, §91.0115(b), the applicant shall submit to the Commission a nonrefundable fee of $75, in addition to the fee required by subparagraph (A) of this paragraph.

(15) An operator must make a check or money order for any of the aforementioned fees payable to the Railroad Commission of Texas. If the check accompanying an application is not honored upon presentment, the Commission or its delegate may suspend or revoke the permit issued on the basis of that application, the allowable assigned, the exception to a statewide rule granted on the basis of the application, the certificate of compliance reissued, or the Natural Gas Policy Act category determination made on the basis of the application.

(16) If an operator submits a check that is not honored on presentment, the operator shall, for a period of 24 months after the check was presented, submit any payments in the form of a credit card, cashier's check, or cash.

(c) Organization Report Fee. An organization report required by Texas Natural Resources Code, §91.142, shall be accompanied by a fee as follows:

(1) for an operator of:

(A) not more than 25 wells, $300;

(B) more than 25 but not more than 100 wells, $500; or

(C) more than 100 wells, $1,000;

(2) for an operator of one or more natural gas pipelines, $225;

(3) for an operator of one or more of the following service activities: pollution cleanup contractor; directional surveying; approved cementer for plugging wells; a cementer of casing strings or liners; or physically moving or storing crude or condensate, $300;

(4) for an operator of one or more liquids pipelines, $625;

(5) for an operator of all other service activities, or facilities, $500;

(6) for an operator with multiple activities, a total fee equal to the sum of the separate fees applicable to each category of service activity, facility, pipeline, or number of wells operated shall be submitted, provided that the total fee for an operator of wells shall not exceed $1,125; and

(7) for an entity not currently performing operations under the jurisdiction of the Commission, $300.

(d) Financial security. Except for those operators exempted under subsection (g)(7) of this section, any person, including any firm, partnership, joint stock association, corporation, or other organization, required by Texas Natural Resources Code, §91.142, to file an organization report with the Commission must also file financial security in one of the following forms:

(1) an individual performance bond;

(2) a blanket performance bond; or

(3) a letter of credit or cash deposit in the same amount as required for an individual performance bond or blanket performance bond.

(e) Forms for financial security and insurance policies. Operators shall submit well-specific plugging insurance policies, bonds and letters of credit on forms prescribed by the Commission.

(f) Filing deadlines for financial security and insurance policies. Operators shall submit required financial security or well-specific plugging insurance policies at the time of filing an initial organization report, as a condition of the issuance of a permit to drill, recomplete or reenter, upon yearly renewal, or as otherwise required under this section.

(g) Amount of financial security. An operator required to file financial security under subsection (d) of this section shall file financial security described in this subsection.

(1) Types and amounts of financial security required.

(A) A person operating one or more wells may file an individual performance bond, letter of credit, or cash deposit in an amount equal to the sum of $2.00 for each foot of total well depth for each well operated, excluding any well bore included in a well-specific plugging insurance policy.

(B) A person operating one or more wells may file a blanket bond, letter of credit, or cash deposit to cover all wells for which a bond, letter of credit, or cash deposit is required in an amount equal to the sum of the base amount determined by the total number of wells operated excluding any well bores and/or permits issued to drill, recomplete, or reenter wells included in a well-specific plugging insurance policy. A person performing multiple operations shall be required to file only one blanket bond, letter of credit, or cash deposit unless the person is operating a commercial facility, in which case the person also shall comply with the financial security requirements of subsection (l) of this section. The financial security amount shall be at least the base amount determined by the total number of wells operated or $25,000, whichever is greater. After excluding any well bores and/or permits issued to drill, recomplete or reenter wells included in a well-specific plugging insurance policy, the base amount is determined as follows:

(i) The base amount for a person operating 10 or fewer wells or performs other operations shall be $25,000.

(ii) The base amount for a person operating more than 10 but fewer than 100 wells shall be $50,000.

(iii) The base amount for a person operating 100 or more wells shall be $250,000.

(2) Additional financial security for bay wells.

(A) All operators of bay wells shall file additional financial security of no less than $60,000 in addition to any other financial security that is required under this section for any other Commission-regulated activities.

(B) For each bay well that is not currently producing oil or gas and has not produced oil or gas within the past 12 months, including injection and disposal wells, the operator shall file additional financial security of $60,000, unless the well bore is included in a well-specific plugging insurance policy that provides benefits of at least $60,000. An operator shall not be required to file additional financial security in addition to the $60,000 amount set under subparagraph (A) of this paragraph if the operator operates only a single inactive bay well.

(C) In the case of a bay well that has been inactive for 12 consecutive months or longer and that is not used for disposal or injection, the well shall remain subject to the provisions of subparagraph (B) of this paragraph, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(3) Additional financial security for offshore wells.

(A) All operators of offshore wells and operators of both bay wells and offshore wells shall file additional financial security of no less than $100,000 in addition to any other financial security that is required under this section for any other Commission regulated activities.

(B) For each offshore well that is not currently producing oil or gas and has not produced oil or gas within the past 12 months, including injection and disposal wells, the operator shall file an additional amount of financial security of $100,000, unless the well bore is included in a well-specific plugging insurance policy that provides benefits of at least $100,000. An operator shall not be required to file additional financial security in addition to the $100,000 amount set under subparagraph (A) of this paragraph if the operator operates only a single inactive offshore well.

(C) In the case of an offshore well that has been inactive for 12 consecutive months or longer and that is not used for disposal or injection, the well shall remain classified as inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(4) Reduction of the additional financial security that is required for bay and/or offshore wells. An operator may request a reduction of either the additional $60,000 in financial security required for all operators of bay wells, or the additional $100,000 in financial security required for all operators of offshore wells and operators of both bay wells and offshore wells.

(A) The director may administratively approve the reduction if the operator provides documentation that it currently has acceptable financial assurance in place to satisfy any financial assurance requirements established by local authorities. The operator must show that the bond or other form of financial assurance can be called on by or assigned to the Commission under the following circumstances:

(i) a well is likely to pollute or is polluting any ground or surface water or is allowing the uncontrolled escape of formation fluids from the strata in which they were originally located; or

(ii) a well is not being maintained in compliance with Commission rules or state law relating to plugging or the prevention or control of pollution; or

(iii) the operator has failed to renew and maintain an organization report filing as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) and this section.

(B) If the director administratively denies a requested reduction, the operator may request a hearing to determine whether the reduction should be granted.

(5) Reduction in additional financial security required for bay and/or offshore wells that are not actively producing oil and natural gas. An operator may request that Commission consider a reduction in any additional financial security requirement for the operation of bay and/or offshore wells that are not actively producing oil and natural gas or that are used for disposal or injection in an amount not to exceed the remainder of 25% of the operator's certified net worth based on the independently audited calculation for the most recently completed fiscal year minus the Commission's estimate of the operator's total plugging liability for all of the operator's active bay and/or offshore wells.

(A) The director may administratively grant a full or partial reduction if the operator meets the following criteria:

(i) the operator has either five or fewer bay and offshore wells or at least half of the operator's bay and offshore wells are actively producing oil and natural gas;

(ii) the operator provides to the Commission certification of its net worth from an independent auditor that has employed generally accepted accounting principles to confirm the operator's stated net worth based on the most recently available and independently audited calculation;

(iii) the reduction is less than or equal to the remainder of 25% of the operator's certified net worth minus the Commission's estimate of the operator's total plugging liability for all of the operator's active bay and offshore wells;

(iv) none of the operator's wells or operations, including any land-based wells, have been found by Commission staff to be violating or to have violated any Commission rule that resulted in pollution or in any hazard to the health or safety of the public in the last 12 months.

(B) If the director administratively denies the requested reduction, an operator may request a hearing to determine if a full or partial reduction should be granted.

(C) The operator may also request a hearing to challenge the Commission's presumed estimate of the operator's plugging liability for bay and offshore wells as applied to any additional financial security required for any inactive bay and offshore wells. The operator shall present clear and convincing evidence that the estimated plugging liability is less than the amount estimated by the Commission. Notice of the hearing shall be provided by the Commission to the owners of the surface estate and the owners of the mineral estate for any well that is a subject of the requested hearing, and all other affected persons as identified by the operator or otherwise required by the Commission.

(6) Persons with non-well operations not exempted under paragraph (7) of this subsection. A person performing other operations who is not an operator of wells and who is not a person whose only activity is as a first purchaser, survey company, gas nominator, gas purchaser or well plugger shall file financial security in the amount of $25,000.

(7) Persons exempt from financial security requirements. No financial security is required of a person who is not an operator of wells if the person's only activity is as a first purchaser, survey company, salt water hauler, gas nominator, gas purchaser and/or well plugger.

(8) Persons with both well and non-well operations. If a person is engaged in more than one activity or operation, including well operation, for which financial security is required, the person is not required to file financial security for each activity or operation in which the person is engaged. The person is required to file financial security only in the greatest amount required for any activity or operation in which the person engages. The financial security filed covers all of the activities and operations for which financial security is required. The provisions of this paragraph do not exempt a person from the financial security required under subsection (l) of this section.

(9) Financial security amounts are the minimum amounts required by this section to be filed. A person may file a greater amount if desired.

(h) Financial security conditions. Any bond, letter of credit, or cash deposit required under this section is subject to the conditions that the operator will plug and abandon all wells and control, abate, and clean up pollution associated with the oil and gas operations and activities covered under the required financial security in accordance with applicable state law and permits, rules, and orders of the Commission. This section does not apply to a well-specific plugging insurance policy.

(i) Conditions for cash deposits and escrow funds. Operators must tender cash deposits and escrow funds in United States currency or certified cashiers check only. The Commission or its delegate will place all cash deposits and escrow funds in a special account within the Oil and Gas Regulation and Cleanup Fund account. The Commission or its delegate will deposit any interest accruing on cash deposits and escrow funds into the Oil and Gas Regulation and Cleanup Fund pursuant to Texas Natural Resources Code, §81.067. The Commission or its delegate may not refund a cash deposit until either financial security is accepted by the Commission or its delegate as provided for under this section or an operator ceases all activity. The Commission or its delegate may release escrow funds to the current operator of the well only if the well for which the operator tendered the escrow funds is either restored to active status or plugged in accordance with Commission rules. In the event that the well is plugged through the use of state funds, the Commission may collect from the escrow account in the amount necessary to reimburse the state for any expenditure.

(j) Well or lease transfer.

(1) The Commission shall not approve a transfer of operatorship submitted for any well or lease unless the operator acquiring the well or lease has on file with the Commission financial security in an amount sufficient to cover both its current operations and the wells or leases being transferred.

(2) Any existing financial security covering the well or lease proposed for transfer shall remain in effect and the prior operator of the well remains responsible for compliance with all laws and Commission rules covering the transferred well until the Commission approves the transfer.

(3) A transfer of a well or lease from one entity to another entity under common ownership is a transfer for the purposes of this section.

(4) The Commission may approve a transfer of operatorship submitted for any well bore included in a well-specific plugging insurance policy if the transfer meets all other Commission requirements.

(k) Reimbursement liability. Filing any form of financial security does not extinguish a person's liability for reimbursement for the expenditure of state oilfield clean-up funds pursuant to Texas Natural Resources Code, §89.083 and 91.113.

(l) Financial security for commercial facilities. The provisions of this subsection shall apply to the holder of any permit for a commercial facility.

(1) Application.

(A) New permits. Any application for a new or amended commercial facility permit filed after the original effective date of this subsection shall include:

(i) a written estimate of the maximum dollar amount necessary to close the facility prepared in accordance with the provisions of paragraph (4) of this subsection that shows all assumptions and calculations used to develop the estimate;

(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission; and

(iii) information concerning the issuer of the bond or letter of credit as required under paragraph (5) of this subsection including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.

(B) Existing permits. Within 180 days of the original effective date of this subsection, the holder of any commercial facility permit issued on or before the original effective date of this subsection shall file with the Commission the information specified in subparagraph (A)(i) - (iii) of this paragraph.

(2) Notice and hearing.

(A) New permits. For commercial facility permits issued after the original effective date of this subsection, the provisions of §3.8 or §3.57 of this title (relating to Water Protection; and Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials), as applicable, regarding notice and opportunity for hearing, shall apply to review and approval of financial security proposed to be filed to meet the requirements of this subsection.

(B) Existing permits. Notice of filing of information required under paragraph (1)(B) of this subsection shall not be required. In the event approval of the financial security proposed to be filed for a commercial facility operating under a permit in effect as of the original effective date of this subsection is denied administratively, the applicant shall have the right to a hearing upon written request. After hearing, the examiner shall recommend a final action by the Commission.

(3) Filing of instrument.

(A) New permits. A commercial facility permitted after the original effective date of this subsection may not receive oil field fluids or oil and gas waste until a bond or letter of credit in an amount approved by the Commission or its delegate under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with the Commission.

(B) Existing permits. Except as otherwise provided in this subsection, after one year from the original effective date of this section, a commercial facility permitted on or before the original effective date of this subsection may not continue to receive oil field fluids or oil and gas waste unless a bond or letter of credit in an amount approved by the Commission or its delegate under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the Commission or its delegate.

(C) Extensions for existing permits. On written request and for good cause shown, the Commission or its delegate may authorize a commercial facility permitted before the original effective date of this subsection to continue to receive oil field fluids or oil and gas waste after one year after the original effective date of this section even though financial security required under this subsection has not been filed. In the event the Commission or its delegate has not taken final action to approve or disapprove the amount of financial security proposed to be filed by the owner or operator under this subsection one year after the original effective date of the section, the period for filing financial security under this subsection is automatically extended to a date 45 days after such final Commission action.

(4) Amount.

(A) Except as provided in subparagraphs (B) or (C) of this paragraph, the amount of financial security required to be filed under this subsection shall be an amount based on a written estimate approved by the Commission or its delegate as being equal to or greater than the maximum amount necessary to close the commercial facility, exclusive of plugging costs for any well or wells at the facility, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit, but shall in no event be less than $10,000.

(B) The owner or operator of one or more commercial facilities may reduce the amount of financial security required under this subsection for one such facility by the amount, if any, it filed as financial security under subsection (g)(6) of this section. The full amount of financial security required under subparagraph (A) of this paragraph shall be required for the remaining commercial facilities.

(C) Except for the facilities specifically exempted under subparagraph (D) of this paragraph, a qualified professional engineer licensed by the State of Texas shall prepare or supervise the preparation of a written estimate of the maximum amount necessary to close the commercial facility as provided in subparagraph (A) of this paragraph. The owner or operator of a commercial facility shall submit the written estimate under seal of a qualified licensed professional engineer to the Commission as required under paragraph (1) of this subsection.

(D) A facility permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials) that does not utilize on-site waste storage or disposal that requires a permit under §3.8 of this title (relating to Water Protection) is exempt from subparagraph (C) of this paragraph.

(E) Notwithstanding the fact that the maximum amount necessary to close the commercial facility as determined under this paragraph is exclusive of plugging costs, the proceeds of financial security filed under this subsection may be used by the Commission to pay the costs of plugging any well or wells at the facility if the financial security for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.

(5) Issuer and form.

(A) Bond. The issuer of any commercial facility bond filed in satisfaction of the requirements of this subsection shall be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection shall provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the Commission or its delegate.

(B) Letter of credit. Any letter of credit filed in satisfaction of the requirements of this subsection shall be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit shall be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101-5.118. The letter of credit shall provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the Commission or its delegate.

(m) Effect of outstanding violations.

(1) Except as provided in paragraph (2) of this subsection, the Commission shall not accept an organization report or an application for a permit or approve a certificate of compliance for an oil lease or gas well submitted by an organization if:

(A) the organization has outstanding violations; or

(B) an officer or owner of the organization, as defined in subsection (a) of this section, was, within seven years preceding the filing of the report, application, or certificate, an officer or owner of an organization and during that period, the organization committed a violation that remains an outstanding violation.

(2) The Commission shall accept a report or application or approve a certificate filed by an organization covered by paragraph (1) of this subsection if:

(A) the conditions that constituted the violation have been corrected or are being corrected in accordance with a schedule agreed to by the organization and the Commission;

(B) all administrative, civil, and criminal penalties, and all plugging and cleanup costs incurred by the state relating to those conditions have been paid or are being paid in accordance with a schedule agreed to by the organization and the Commission; and

(C) the report, application or certificate is in compliance with all other requirements of law and Commission rules.

(3) All fees tendered in connection with a report or application that is rejected under this subsection are nonrefundable.

(n) Mandatory surcharges. The Commission adopts this subsection pursuant to Texas Natural Resources Code, §81.070, to impose reasonable surcharges as necessary on fees collected by the Commission that are required to be deposited to the credit of the Oil and Gas Regulation and Cleanup Fund, as provided by Texas Natural Resources Code, §81.067, in an amount sufficient to enable the Commission to recover the costs of performing the functions specified by Texas Natural Resources Code, §81.068, from those fees and surcharges. This subsection establishes the methodology the Commission shall use to determine the amount of the surcharge on each fee, as required by Texas Natural Resources Code, §81.070(c).

(1) For all fees subject to a surcharge under this section, the Commission shall employ a projected cost-based recovery methodology derived from budgeted cost projections approved by the Legislature in the General Appropriations Act, which is dependent upon revenue projections issued by the Comptroller in the most recent Biennial Revenue Estimate. In establishing the surcharge amounts, the Commission shall consider the factors and values set forth in the following subparagraphs.

(A) The Commission shall ascertain the time required to complete the regulatory work associated with the activity in connection with which the surcharge is imposed using the number of full-time equivalent positions (FTEs) appropriated by the Legislature for that purpose during the applicable biennium, multiplied by the work hours in a fiscal year, divided by the anticipated number of permit applications processed in a fiscal year.

(B) The Commission shall use the number of P-5

Organization Reports as a proxy to determine the number of individual or entities from which the Commission's costs may be recovered. An Organization Report is required to be filed and renewed annually by any organization, including any person, firm, partnership, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, that performs operations within the jurisdiction of the agency.

(C) The Commission shall determine how the surcharge will affect operators considered to be large, based on operating more than 10,000 oil or gas wells; operators considered to be medium, based on operating more than 1,000 oil or gas wells, but fewer than 10,000 wells; and operators considered to be small, based on operating fewer than 1,000 oil or gas wells.

(D) The Commission shall consider the balance of the Oil and Gas Regulation and Cleanup Fund at the beginning of the fiscal year in which the surcharge is assessed.

(E) The Commission shall assume that the Legislature intended that the agency's oil and gas regulatory program should be self-funded. The Commission shall maintain an adequate balance in the Oil and Gas Regulation and Cleanup Fund such that the regulatory program can withstand a decrease in industry activity without sacrificing the health and public safety aspects of its regulatory work, while also having funds available to respond to any emergency related to oil and gas activity throughout the state. The Commission shall also maintain a fund balance that is within the statutory fund limits as determined by the Legislature.

(2) The Commission shall consider the factors set forth in paragraph (1) of this subsection to determine the surcharge applicable to all fees deposited to the Oil and Gas Regulation and Cleanup Fund in the following manner:

(A) the Commission shall first apply the premise that the oil and gas regulatory program should be self-funded;

(B) the Commission shall then apply a cost-based recovery analysis to the funding levels determined by the Legislature. The Commission shall rely primarily on these two factors, but shall also review all factors and values set forth in subparagraph (A) of this paragraph; and

(C) the Commission will apply the surcharge rate to all applicable fees as detailed in paragraph (3) of this subsection.

(3) Based on the factors and methodology set forth in this subsection, the Commission has determined that a surcharge rate of 150 percent will be necessary on all fees required to be deposited to the credit of the Oil and Gas Regulation and Cleanup Fund.

(4) The Commission shall review the surcharge rate determination under this subsection periodically but not less than each biennium to confirm that the imposed surcharge is reasonable.

Source Note: The provisions of this §3.78 adopted to be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective October 12, 2003, 28 TexReg 8890; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective December 19, 2005, 30 TexReg 8426; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective May 1, 2012, 37 TexReg 1315; amended to be effective August 27, 2012, 37 TexReg 6538; amended to beeffective December 16, 2013, 38 TexReg 9010; amended to be effective February 1, 2016, 41 TexReg 792.

§3.79 Definitions

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Adjacent estuarine zones--This term embraces the area inland from the coast line of Texas and is comprised of the bays, inlets, and estuaries along the gulf coast.

(2) By-product--Any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducing energy generation.

(3) Casinghead gas--Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(4) Commission--The Railroad Commission of Texas.

(5) Common reservoir--Any oil, gas, or geothermal resources field or part thereof which comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil, gas, or geothermal resources.

(6) Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

(7) District office--The commission-designated office for the geographic area in which the property or act subject to regulation is located or arises.

(8) Dry gas--Any natural gas produced from a stratum

that does not produce crude petroleum oil.

(9) Exploratory well--Any well drilled for the purpose of securing geological or geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal and uranium, and includes what is commonly referred to in the industry as "slim hole tests," "core hole tests," or "seismic holes." For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(10) Gas lift--Gas lift by the use of gas not in solution with oil produced.

(11) Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

(12) Gatherer--Includes any pipeline, truck, motor vehicle, boat, barge, or person authorized to gather or accept oil, gas, or geothermal resources from lease production or lease storage.

(13) Geothermal energy and associated resources--

(A) All products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured water;

(B) Steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(C) Heat or other associated energy found in geothermal formations;

(D) Any by-product derived from them.

(14) Geothermal resource well--A well drilled within the established limits of a designated geothermal field.

(A) A geopressured geothermal well must be completed within a geopressured aquifer.

(B) A geopressured aquifer is a water-bearing zone with a pressure gradient in excess of 0.5 pounds per square inch per foot and a temperature gradient in excess of 1.6 degrees Fahrenheit per 100 feet of depth.

(15) Marginal well--Any oil well which is incapable of producing its maximum capacity of oil except by pumping, gas lift, or other means of artificial lift, and which well so equipped is capable, under normal unrestricted operating conditions, of producing such daily quantities of oil as herein set out, as would be damaged, or result in a loss of production ultimately recoverable, or cause the premature abandonment of same, if its maximum daily production were artificially curtailed. The following described wells shall be deemed "marginal wells" in this state.

(A) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 10 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a depth of 2,000 feet or less.

(B) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 20 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 2,000 feet and less in depth than 4,000 feet.

(C) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 25 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 4,000 feet and less in depth than 6,000 feet.

(D) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 30 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 6,000 feet and less in depth than 8,000 feet.

(E) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 35 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 8,000 feet. (Reference Order Number 20-59,200, effective May 1, 1969.)

(16) Natural gas or gas--These terms shall have the same meaning, as used in the rules, regulations, or forms of the commission.

(17) Natural gasoline--Gasoline manufactured from casinghead gas or from any natural gas.

(18) Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.

(19) Operator--A person, acting for himself or as an agent for others and designated to the commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the commission.

(20) Person--Any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, and a fiduciary or representative of any kind.

(21) Product--Includes refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, casinghead gasoline, natural gas gasoline, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum, and/or any and all liquid products or by-products derived from crude petroleum oil or gas, whether hereinabove enumerated or not.

(22) Sour gas--Any natural gas containing more than 1 1/2 grains of hydrogen sulphide per 100 cubic feet or more than 30 grains of total sulphur per 100 cubic feet, or gas which in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

(23) Sweet gas--All natural gas except sour gas and casinghead gas.

(24) Texas offshore--This term embraces the area in the Gulf of Mexico seaward of the coast line of Texas comprised of:

(A) the three league area confirmed to the State of Texas by the Submerged Land Act (43 United States Code §§1301-1315); and

(B) the area seaward of such three league area owned by the United States.

(25) Transportation or to transport--The movement of any crude petroleum oil or products of crude petroleum oil or the products of either from any receptacle in which any such crude petroleum or products of crude petroleum oil or the products of either has been stored to any other receptacle by any means or method whatsoever, including the movement by any pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car. It is the purpose of this definition to include the movement or transportation of crude petroleum oil and products of crude petroleum oil and the products of either by any means whatsoever from any receptacle containing the same to any other receptacle anywhere within or from the State of Texas, regardless of whether or not possession or control or ownership change.

(26) Transporter or transporting agency--Includes any common carrier by pipeline, railway, truck, motor vehicle, boat, or barge, and/or any person transporting oil or a product by pipeline, railway, truck, motor vehicle, boat, or barge.

(27) Underground source of drinking water--An aquifer or its portion which is not an exempt aquifer as defined in 40 Code of Federal Regulations §146.4 and which:

(A) supplies any public water system; or

(B) contains a sufficient quantity of ground water to supply a public water system; and

(i) currently supplies drinking water for human consumption; or

(ii) contains fewer than 10,000 milligrams per liter (mg/l) total dissolved solids.

Source Note: The provisions of this §3.79 adopted to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.80 Commission Oil and Gas Forms, Applications, and Filing Requirements

(a) Forms. Forms required to be filed at the Commission shall be those prescribed by the Commission. A complete set of all Commission forms required to be filed at the Commission shall be kept by the Commission secretary and posted on the Commission's web site. Notice of any new or amended forms shall be issued by the Commission. For any required or discretionary filing, an organization may either file the prescribed form on paper or use any electronic filing process in accordance with subsections (e) or (f) of this section, as applicable. The Commission may at its discretion accept an earlier version of a prescribed form, provided that it contains all required information and meets the requirements of subsection (e)(3) of this section.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Electronic filing process--An electronic transmission to the Commission in a prescribed form and/or format authorized by the Commission and completed in accordance with Commission instructions.

(3) Form--A printed or typed paper document or electronic submission, including any necessary instructions, with blank spaces for insertion of required or requested specific information.

(4) Organization--Any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission.

(5) Position of ownership or control--A person holds a position of ownership or control in an organization if the person is:

(A) an officer or director of the organization;

(B) a general partner of the organization;

(C) the owner of an organization which is a sole proprietorship;

(D) the owner of more than a 25 percent ownership interest in the organization; or

(E) the designated trustee of the organization.

(6) Violation--Non-compliance with a statute, Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(c) Organization eligibility. The Commission may not accept an organization report or an application for a permit, or approve a certificate of compliance if:

(1) the organization that submitted the report, application, or certificate violated a statute or Commission rule, order, license, certificate, or permit that relates to safety or the prevention or control of pollution; or

(2) any person who holds a position of ownership or control in the organization has, within the seven years preceding the date on which the report, application, or certificate is filed, held a position of ownership or control in another organization, and during that period of ownership or control the other organization violated a statute or Commission rule, order, license, permit, or certificate that relates to safety or the prevention or control of pollution.

(d) Violations. An organization has committed a violation if there is either a Commission order against an organization finding that the organization has committed a violation and all appeals have been exhausted or an agreed order entered into by the Commission and an organization relating to an alleged violation, and:

(1) the conditions that constituted the violation or alleged violation have not been corrected;

(2) all administrative, civil and criminal penalties, if any, relating to the violation or agreed settlement relating to an alleged violation have not been paid; or

(3) all reimbursements of costs and expenses, if any, assessed by the Commission relating to the violation or to the alleged violation have not been collected.

(e) Authorization and standards for electronic filing.

(1) An organization may file electronically any form for which the Commission has provided an electronic version, provided that the organization pays all required filing fees and complies with all requirements, including but not limited to security procedures, for electronic filing.

(2) The Commission deems an organization that files electronically or on whose behalf is filed electronically any form, as of the time of filing, to have knowledge of and to be responsible for the information filed on the form, pursuant to the statutory requirements, restrictions, and standards found in and pertaining to:

(A) Texas Natural Resources Code, Title 3 (oil and gas well drilling, production, and plugging);

(B) Texas Natural Resources Code, Title 5 (geothermal resources);

(C) Texas Natural Resources Code, Title 11 (hazardous liquids storage);

(D) Texas Utilities Code, Chapter 121, Subchapter I (sour gas pipeline facilities);

(E) Texas Water Code, §26.131 (discharge permits);

(F) Texas Water Code, Chapter 27 (class II injection and disposal wells and class III brine mining wells);

(G) Texas Water Code, Chapter 29 (oil and gas waste haulers);

(H) Texas Health and Safety Code, §401.415 (oil and gas naturally occurring radioactive material (NORM) waste); and

(I) Texas Administrative Code, Title 16, Chapter 3 (Oil and Gas Division) and Chapter 4 (Environmental Protection).

(3) All forms that an organization submits or that are submitted on behalf of an organization shall be transmitted in the manner prescribed by the Commission that is compatible with its software, equipment, and facilities.

(4) The Commission may provide notice electronically to an organization of, and may provide an organization the ability to confirm electronically, the Commission's receipt of a form submitted electronically by or on behalf of that organization.

(5) The Commission deems that the signature of an organization's authorized representative appears on each form submitted electronically by or on behalf of the organization, as if this signature actually appears, as of the time the form is submitted electronically to the Commission.

(6) The Commission holds each organization responsible, under the penalties prescribed in Texas Natural Resources Code, §91.143, for all forms, information, or data that an organization files or that are filed on its behalf. The Commission charges each organization with the obligation to review and correct, if necessary, all forms or data that an organization files or that are filed on its behalf.

(f) Other electronic transmissions. The Commission may at its discretion accept other documents or data electronically transmitted.

Source Note: The provisions of this §3.80 adopted to be effective June 11, 2001, 26 TexReg 4088; amended to be effective April 12, 2004, 29 TexReg 3612; amended to be effective July 12, 2004, 29 TexReg 6633; amended to be effective October 11, 2004, 29 TexReg 9533; amended to be effective April 3, 2006, 31 TexReg 2846; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective January 7, 2008, 33 TexReg 114; amended to be effective September 12, 2011, 36 TexReg 5835; amended to be effective July 7, 2014, 39 TexReg 5148.

§3.81 Brine Mining Injection Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine mining facility or facility--The brine mining injection well, and the pits, tanks, fresh water wells, pumps, and other structures and equipment that are or will be used in conjunction with the brine mining injection well.

(3) Brine mining injection well--A well used to inject fluid for the purpose of extracting brine by the solution of a subsurface salt formation. The term "brine mining injection well" does not include a well used to inject fluid for the purpose of leaching a cavern for the underground storage of hydrocarbons or the disposal of waste, or a well used to inject fluid for the purpose of extracting sulphur by the thermofluid mining process.

(4) Commission--The Railroad Commission of Texas.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(6) Existing brine mining injection well--A brine mining injection well in which injection operations began prior to the effective date of this section.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(8) New brine mining injection well--A brine mining injection well in which injection operations begin on or after the effective date of this section.

(9) Permit--A written authorization issued by the commission under this section for the operation of a brine mining injection well.

(10) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust partnership, association, or any other legal entity.

(11) Pollution--The alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(b) Prohibitions.

(1) Unauthorized injection. No person may operate a brine mining injection well without obtaining a permit from the commission under this section. No person may begin constructing a new brine mining injection well until the commission has issued a permit to operate the well under this section and a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(2) Fluid migration. No person may operate a brine mining injection well in a manner that allow fluids to escape from the permitted injection zone. If fluids are migrating from the permitted injection zone, the operator shall immediately cease injection operations.

(3) Falsifying documents and tampering with gauges. No person may knowingly make any false statement, representation, or certification in any application, report, record, or other document submitted or required to be maintained under this section or under any permit issued pursuant to this section, or falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under this section or under any permit issued pursuant to this section.

(c) Standards for permit issuance. A permit may be issued only if the commission determines that the operation of the brine mining injection well will not result in the pollution of fresh water. All permits issued under this section will contain the conditions required by subsections (f) and (g) of this section, and all other components and casing shall be inspected at least once every 15 years for corrosion, cracks, deformations, or other conditions that may compromise integrity and that may not be detected by the five-year test. The operator may request an extension of up to five years from the Commission for good cause. Factors the Commission may consider in determining good cause pursuant to this paragraph include by are not limited to the age, location, and configuration of the well; well and facility history; operator compliance record; operator efforts to comply with this subsection; and accuracy of inventory control.

(4) Fresh water, brine, and gas surface piping. Within one year of the effective date of this section, the operator shall submit a piping integrity management plan for approval by the Commission or its designee. Within three years of the effective date of this section, or in conjunction with the storage well integrity testing, all gas, freshwater, and brine surface piping shall be maintained according to the facility's piping integrity management plan.

(p) Plugging.

(1) Plug on abandonment. A gas storage well shall be plugged upon permanent abandonment in a manner approved by the Commission or its designee. A proposal for plugging shall be submitted to the Commission in Austin for approval or modification prior to plugging. Following approval of a plugging plan, the operator shall file notification of intent to plug at least five days prior to commencement of plugging operations. A plugging report shall be filed with the Commission within 30 days after plugging.

(2) Alternative monitoring. As an alternative to plugging a gas storage well that has been permanently deactivated, an operator may request approval by the Commission or its designee of a plan to convert the well to a monitor well. A pressure monitoring plan must be submitted to the Commission along with the request to convert the well to a monitoring well.

(q) Penalties.

(1) Penalties. Violations of this section may subject the operator to penalties and remedies specified in Texas Natural Resources Code, Title 3; Texas Utilities Code, Chapter 121; and other statutes administered by the Commission.

(2) Certificate of compliance. The certificate of compliance for any underground gas storage facility may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) for violation of this section.

(r) Applicability of other Commission rules and orders. The owner or operator of an underground gas storage facility is not relieved by this section of compliance with any other requirement of Chapters 3, 4, 7, or 8 of this title (relating to Oil and Gas Division; Environmental Protection; Gas Services Division; or Pipeline Safety Regulations).

Source Note: The provisions of this §3.97 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 289; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.98 Standards for Management of Hazardous Oil and Gas Waste

(a) Purpose. The purpose of this section is to establish standards for management of hazardous oil and gas waste.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil, gas, or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil, gas, or geothermal resources;

(iii) activities associated with natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph.

(2) Administrator--The administrator of the United States Environmental Protection Agency, or the administrator's designee.

(3) Authorized facility--Either:

(A) an authorized recycling or reclamation facility; or

(B) an authorized treatment, storage, or disposal facility.

(4) Authorized recycling or reclamation facility--A facility permitted in accordance with the requirements of 40 CFR, Parts 270 and 124 or Part 271, if required, at which hazardous waste that is to be recycled or reclaimed is managed and whose owner or operator is subject to regulation under:

(A) 40 CFR, §261.6(c) or an equivalent state program (concerning facilities that recycle recyclable materials); or

(B) 40 CFR, Part 266, Subparts C (concerning recyclable materials used in a manner constituting disposal), F (concerning recyclable materials used for precious metal recovery), or G (concerning spent lead-acid batteries being reclaimed), or an equivalent state program.

(5) Authorized representative--The person responsible for the overall operation of all or any part of a facility or generation site.

(6) Authorized treatment, storage, or disposal facility--A facility at which hazardous waste is treated, stored, or disposed of that:

(A) has received either:

(i) a permit (or interim status) in accordance with the requirements of 40 CFR, Parts 270 and 124 (EPA permit); or

(ii) a permit (or interim status) from a state authorized in accordance with 40 CFR, Part 271; and

(B) is authorized under applicable state or federal law to treat, store, or dispose of that type of hazardous waste. If a hazardous oil and gas waste is destined to a facility in an authorized state that has not yet obtained authorization from the EPA to regulate that particular hazardous waste, then the designated facility must be a facility allowed by the receiving state to accept such waste and the facility must have a permit issued by the EPA to manage that waste.

(7) Centralized Waste Collection Facility or CWCF--A facility that meets the requirements of subsection (m)(3) of this section.

(8) Certification--A statement of professional opinion based upon knowledge and belief.

(9) CFR--Code of Federal Regulations.

(10) CESQG--A conditionally exempt small quantity generator, as described in subsection (f)(1) of this section (relating to generator classification and accumulation time).

(11) Commission--The Railroad Commission of Texas or its designee.

(12) Container--Any portable device in which material is stored, transported, treated, disposed of, or otherwise handled.

(13) Contaminated media--Soil, debris, residues, waste, surface waters, ground waters, or other materials containing hazardous oil and gas waste as a result of a discharge or clean-up of a discharge.

(14) Department of Transportation or DOT--The United States Department of Transportation.

(15) Designated facility--An authorized facility that has been designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section (relating to general manifest requirements).

(16) Discharge or hazardous waste discharge--The accidental or intentional spilling, leaking, pumping, pouring, emitting, emptying, or dumping of hazardous waste into or on any land or water.

(17) Disposal--The discharge, deposit, injection, dumping, spilling, leaking, or placing of any hazardous waste into or on any land or water so that such waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

(18) Disposal facility--A facility or part of a facility at which hazardous waste is intentionally placed into or on any land or water, and at which waste will remain after closure.

(19) Elementary neutralization unit--A device consisting of a tank, tank system, container, transport vehicle, or vessel that is used for neutralizing wastes that are hazardous wastes:

(A) only because they exhibit the characteristic of corrosivity under the test referred to in subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes); or

(B) they are identified in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) only because they exhibit the corrosivity characteristic.

(20) Empty container--A container or an inner liner removed from a container that has held any hazardous waste and that meets the requirements of 40 CFR, §261.7(b).

(21) Environmental Protection Agency or EPA--The United States Environmental Protection Agency.

(22) EPA Acknowledgment of Consent--The cable sent to the EPA from the United States Embassy in a receiving country that acknowledges the written consent of the receiving country to accept the hazardous waste and describes the terms and conditions of the receiving country's consent to the shipment.

(23) EPA hazardous waste number--The number assigned by the EPA to each hazardous waste listed in 40 CFR, Part 261, Subpart D, and to each characteristic identified in 40 CFR, Part 261, Subpart C.

(24) EPA identification number or EPA ID Number--The number assigned by the EPA to each hazardous waste generator, transporter, and treatment, storage, or disposal facility.

(25) EPA Form 8700-12--The EPA form that must be completed and delivered to the commission in order to obtain an EPA ID number.

(26) Executive director of the TCEQ--The executive director of the TCEQ or the executive director's designee.

(27) Facility--All contiguous land, including structures, other appurtenances, and improvements on the land, used for recycling, reclaiming, treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (e.g., one or more landfills, surface impoundments, or combinations thereof).

(28) Generate--To produce hazardous oil and gas waste or to engage in any activity (such as importing) that first causes a hazardous oil and gas waste to become subject to regulation under this section.

(29) Generation site--

(A) Excluding sites addressed in subparagraphs (B) (relating to pipelines) and (C) (relating to gas plants) of this paragraph, any of the following operational units that are owned or operated by one person and other sites at which hazardous oil and gas waste is generated or where actions first cause a hazardous oil and gas waste to become subject to regulation, including but not limited to:

(i) all oil and gas wells that produce to one set of storage or treatment vessels, such as a tank battery, the storage or treatment vessels, associated flowlines, and related land surface;

(ii) an injection or disposal site, that is not part of a generation site described in subparagraph (A)(i) of this paragraph, its related injection or disposal wells, associated injection lines, and related land surface;

(iii) an offshore platform; or

(iv) any other site, including all structures, appurtenances, or other improvements associated with that site that are geographically contiguous, but which may be divided by public or private right-of-way, provided the entrance and exit between the properties is at a cross-roads intersection, and access is by crossing as opposed to going along, the right-of-way.

(B) In the case of a pipeline system (other than a field flowline or injection line system), an equipment station (such as a pump station, breakout station, or compressor station) or any other location along a pipeline (such as a drip pot, pigging station, or rupture), together with any and all structures, other appurtenances, and improvements:

(i) that are geographically contiguous with or are physically related to an equipment station or other location described in this paragraph, but excluding any pipeline that connects two or more such stations or locations;

(ii) that are owned or operated by one person; and

(iii) at which hazardous oil and gas waste is produced or where actions first cause a hazardous oil and gas waste to become subject to regulation.

(C) A natural gas treatment or processing plant or a natural gas liquids processing plant.

(30) Generator--Any person, by generation site, whose act or process produces hazardous oil and gas waste or whose act first causes a hazardous oil and gas waste to become subject to regulation under this section, or such person's authorized representative.

(31) Geothermal energy and associated resources Geothermal energy and associated resources as defined in Texas Natural Resources Code, §141.003(4).

(32) Hazardous oil and gas waste--Any oil and gas waste determined to be hazardous under the provisions of subsection (e) of this section (relating to hazardous waste determination).

(33) Hazardous oil and gas waste constituent--A hazardous waste constituent of hazardous oil and gas waste.

(34) Hazardous waste--A hazardous waste, as defined in 40 CFR, §261.3, including a hazardous oil and gas waste.

(35) Hazardous waste constituent--A constituent that caused the administrator to list a hazardous waste in 40

CFR, Part 261, Subpart D, or a constituent listed in table 1 of 40 CFR, §261.24.

(36) International shipment--The transportation of hazardous oil and gas waste into or out of the jurisdiction of the United States.

(37) Land disposal--The placement in or on the land, except as otherwise provided in 40 CFR, Part 268, including placement in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave, or placement in a concrete vault or bunker intended for disposal purposes.

(38) LQG--A large quantity generator, as described in subsection (f)(3) of this section (relating to generator classification and accumulation time).

(39) Management--The systematic control of the collection, source separation, storage, transportation, processing, treatment, recovery, and disposal of hazardous waste.

(40) Manifest--The shipping document required pursuant to the provisions of subsection (o) of this section (relating to manifests).

(41) Manifest document number--The 12-digit identification number assigned to a generator by the EPA, plus a unique five-digit document number assigned to the manifest by the generator, or preprinted on the manifest, for recording and reporting purposes.

(42) Oil and gas waste--Waste generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, or the solution mining of brine. Until delegation of authority under RCRA to the commission by EPA, the term "oil and gas waste" shall exclude hazardous waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants and reservoir pressure maintenance or repressurizing plants.

(43) On-site--At the generation site.

(44) Operator--The person responsible for the overall operation of a facility.

(45) Owner--The person who owns a facility or part of a facility.

(46) P-5 operator number--The number assigned by the commission to each person who conducts any of the activities specified in §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) within the State of Texas.

(47) Person--An individual, firm, joint stock company, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(48) Pressure maintenance plant or repressurizing plant--A plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurizing) in a natural gas recycling project. These terms do not include a compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system.

(49) Primary exporter--Any person who is required to originate the manifest for a shipment of hazardous waste in accordance with 40 CFR, Part 262, Subpart B, or equivalent state provision, that identifies a treatment, storage, or disposal facility in a receiving country as the facility to which the hazardous waste will be sent and any intermediary arranging for the export.

(50) Receiving country--A foreign country to which a hazardous waste is sent for the purpose of treatment, storage, or disposal (except short-term storage incidental to transportation).

(51) Reclaim--To process to recover a usable product or to regenerate.

(52) Recycle--To beneficially use, reuse, or reclaim hazardous waste.

(53) Reportable quantity--The quantity of a hazardous substance released in a 24-hour period that must be reported under the provisions of 40 CFR, Part 117 (for spills to water) or Part 302 (any spill).

(54) Resource Conservation and Recovery Act or RCRA--The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended, 42 USC §6901, et seq.

(55) Reuse--To employ hazardous waste as an ingredient in an industrial process to make a product (other than recovery of distinct components of hazardous waste as separate end products) or effective substitution of hazardous waste for a commercial product used in a particular function or application.

(56) Sludge--Any solid, semi-solid, or liquid waste generated from a wastewater treatment plant or water supply treatment plant, or air pollution control facility, exclusive of the treated effluent from a wastewater treatment plant.

(57) Solid waste--Any waste identified in 40 CFR, §261.2.

(58) Solution mined brine--Brine extracted from a subsurface salt formation through dissolution of salt in the formation.

(59) SQG--A small quantity generator, as described in subsection (f)(2) of this section (relating to generator classification and accumulation time).

(60) State--Any of the 50 states that compose the United States, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands.

(61) Storage--The holding of hazardous waste for a temporary period (excluding storage at the site of generation during the applicable accumulation time period specified in subsection (f) of this section), at the end of which the hazardous waste is recycled, reclaimed, treated, disposed of, or stored elsewhere.

(62) Tank--A stationary device designed to contain an accumulation of hazardous waste that is constructed primarily of non-earthen materials (e. g., wood, concrete, steel, plastic) that provide structural support.

(63) Tank system--A tank and its associated ancillary equipment and containment system.

(64) TCEQ--The Texas Commission on Environmental Quality or its successor agencies.

(65) Totally enclosed treatment facility--A facility for the treatment of hazardous waste that is directly connected to an industrial production process and that is constructed and operated in a manner that prevents the release of any hazardous waste or hazardous waste constituent into the environment during treatment (e.g., a pipe in which waste acid is neutralized).

(66) Transfer facility--Any transportation-related facility including loading docks, parking areas, storage areas, and other similar areas where shipments of hazardous waste are held during the normal course of transportation.

(67) Transport vehicle--A motor vehicle or rail car used for the transportation of cargo. Each cargo-carrying body (trailer, railroad freight car, etc.) is a separate transport vehicle.

(68) Transportation--The movement of hazardous waste by air, rail, highway, or water.

(69) Transporter--A person engaged in the off-site transportation of hazardous waste.

(70) Treatment--Any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of any hazardous waste so as to neutralize such waste, to recover energy or material resources from the waste, or to render such waste non-hazardous or less hazardous, safer to transport, store, or dispose of, amenable for recovery or storage, or reduced in volume. The term does not include any activity that might otherwise be considered treatment that is exempt from regulation under this section (such as neutralization of caustic or acidic fluids in an elementary neutralization unit).

(71) TCEQ-Form 0311--The TCEQ Uniform Hazardous Waste Manifest form. This form can be obtained from the commission.

(72) United States--The 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

(73) Used Oil--Any oil that has been refined from crude oil, or any synthetic oil, that has been used and as a result of such use is contaminated by physical or chemical impurities.

(74) Vessel--Every description of watercraft used or capable of being used as a means of transportation on the water. The term does not include a structure that is or is designed to be, permanently affixed to one location, or a drilling or workover vessel that is stationary or fixed for the performance of its primary function.

(75) Waste--Any solid waste, as that term is defined in 40 CFR, §261.2.

(76) Wastewater treatment unit--A device (such as a hydrostatic test water treatment unit) that:

(A) is a tank or tank system comprising part of a wastewater treatment facility that is subject to regulation under either §§402 or 307(b) of the Clean Water Act, 33 USC §§1342 or 1317(b); and

(B) receives and treats or stores an influent wastewater that is a hazardous waste, that generates and accumulates a wastewater treatment sludge that is a hazardous waste, or treats or stores a wastewater treatment sludge that is a hazardous waste.

(77) Water (bulk shipment)--The bulk transportation of hazardous waste that is loaded or carried on board a vessel without containers or labels.

(c) Applicability.

(1) General.

(A) This section applies to any person who generates hazardous oil and gas waste and to any person who transports hazardous oil and gas waste.

(B) An owner or operator of a treatment, storage, or disposal facility regulated by the TCEQ's industrial and hazardous waste program, shall be subject to the standards for generators of hazardous waste found in Title 30, Texas Administrative Code, Chapter 335, Subchapter C (TCEQ standards for generators) if the facility generates a new waste that contains hazardous oil and gas waste and waste regulated by the TCEQ's industrial and hazardous waste program.

(2) Requirements Cumulative. The provisions of this section are in addition to applicable provisions contained

in any other section, order, policy, rule, or statutory authority of the commission. In the event of a conflict between this section and any other section, order, policy, or rule of the commission, this section shall control.

(d) General Prohibitions. No person may cause, suffer, allow, or permit the collection, handling, storage, transportation, treatment, or disposal of hazardous oil and gas waste in a manner that would violate the provisions of this section.

(e) Hazardous Waste Determination.

(1) Determination. A person who generates a waste shall determine if such waste is hazardous oil and gas waste as provided in this subsection. A hazardous oil and gas waste is a waste that:

(A) is defined in subsection (b) of this section (relating to definitions) as an oil and gas waste;

(B) is not described in 40 CFR, §261.4(a) (which describes wastes that are not considered solid wastes);

(C) is not described in 40 CFR, §261.4(b) (which describes solid wastes that are exempt from regulation under RCRA Subtitle C); and

(D) is identified as a hazardous waste either:

(i) in 40 CFR, Part 261, Subpart D (regarding listed hazardous wastes); or

(ii) in 40 CFR, Part 261, Subpart C (regarding characteristically hazardous wastes), as determined either:

(I) by testing the waste:

(-a-) in accordance with methods described in 40 CFR, Part 261, Subpart C; or

(-b-) in accordance with an equivalent method approved by the administrator under 40 CFR, §260.21; or

(II) by applying knowledge of the hazard characteristics of the waste in light of the materials or processes used.

(2) Land Ban. Each LQG and SQG shall determine whether the hazardous oil and gas waste it generates is prohibited from land disposal under the provisions of 40 CFR, Part 268. If the waste is prohibited from land disposal, the LQG or SQG must comply with all applicable provisions of 40 CFR, Part 268 (concerning management of land ban wastes) prior to disposing of such waste.

(3) Exclusions and Exemptions.

(A) Notwithstanding the provisions of subsection (e)(1) of this section, in the event the administrator determines, in accordance with the provisions of 40 CFR, §260.22, that a particular oil and gas waste that is considered a hazardous oil and gas waste because it meets criteria set out in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) should not be considered a hazardous waste, such waste shall be exempt from regulation under this section.

(B) Notwithstanding the provisions of subsection (e)(1) of this section the following are exempt from regulation under this section:

(i) any oil and gas waste described in 40 CFR, §261.6(a)(2) (concerning recyclable materials) that is managed as provided in applicable provisions of 40 CFR, Part 266, Subparts C - H, and 40 CFR, Parts 270 and 124;

(ii) any oil and gas waste described and recycled, reclaimed, or reused as provided in 40 CFR, §261.6(a)(3) (concerning recyclable materials);

(iii) used oil that is not considered a hazardous waste under the provisions of 40 CFR, §279.10(b) and that is managed as provided in 40 CFR, Part 279;

(iv) dielectric fluid containing polychlorinated biphenyls (PCBs) and electric equipment containing such fluid that are regulated under 40 CFR, Part 761 and that are hazardous only because they exhibit the characteristic of toxicity for D018-D043 under the test required under subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes);

(v) debris, as that term is defined in 40 CFR, §268.2, that is an oil and gas waste:

(I) that contains or contained a hazardous oil and gas waste listed in 40 CFR, Part 261, Subpart D or that exhibits or exhibited a hazardous waste characteristic identified in 40 CFR, Part 261, Subpart C; and

(II) that has been treated using one of the required destruction technologies specified in Table 1 of 40 CFR, §268.45 or that is determined by the administrator to be no longer contaminated with hazardous oil and gas waste; and

(vi) hazardous oil and gas waste remaining in an empty container.

(f) Generator Classification and Accumulation Time.

(1) Conditionally Exempt Small Quantity Generator.

(A) To be classified as a conditionally exempt small quantity generator (CESQG) during any calendar month, a generator of hazardous oil and gas waste must:

(i) generate no more than 100 kilograms (220.46 pounds) of hazardous oil and gas waste in that calendar month; and

(ii) accumulate no more than 1,000 kilograms (2204.60 pounds) of hazardous oil and gas waste on-site at any one time.

(B) Except as provided in subsection (f)(5) of this section, a CESQG must comply with all requirements of this section applicable to CESQGs.

(C) If a CESQG generates in one calendar month, or accumulates on-site at any one time, more than a total of one kilogram (2.20 pounds) of any acute hazardous waste listed in 40 CFR, §261.31, 261.32 or 261.33(e) or a total of 100 kilograms (220.46 pounds) of contaminated media resulting from the clean up of a discharge into or on any land or water of any acute hazardous waste listed in 40 CFR, §261.31, 261.32, or 261.33(e), all such acute hazardous wastes must be managed as though generated by an LQG. The LQG accumulation time period for such acute hazardous wastes shall begin at such time as the maximum quantity specified in this subparagraph is exceeded.

(2) Small Quantity Generator.

(A) To be classified as a small quantity generator (SQG) in any calendar month, a generator of hazardous oil and gas waste must:

(i) generate less than 1,000 kilograms (2204.60 pounds) of hazardous oil and gas waste in that calendar month;

(ii) not allow any particular quantity of hazardous oil and gas waste to remain on-site for a period of more than:

(I) 180 days from the date that particular quantity was generated; or

(II) 270 days from the date that particular quantity was generated, but only if the waste must be transported or offered for transport to a treatment, storage, or disposal facility that is located a distance of 200 miles or more from the point of generation; and

(iii) not accumulate more than 6,000 kilograms (13,227.60 pounds) of hazardous oil and gas waste on-site at any one time.

(B) An SQG must accumulate all hazardous oil and gas waste in tanks or containers that meet the requirements of this section and, except as provided in subsection (f)(5) of this section, comply with all requirements of this section applicable to SQGs.

(C) The accumulation period specified in subsection (f)(2)(A)(ii) of this section may be extended an additional 30 days if the commission, at its sole discretion, determines that unforeseen, temporary, and uncontrollable circumstances require that hazardous oil and gas waste remain on-site for a longer time period.

(3) Large Quantity Generators.

(A) Any generator of hazardous oil and gas waste not classified as a CESQG or SQG is classified as a large quantity generator (LQG).

(B) An LQG must accumulate hazardous oil and gas waste in tanks or containers that meet the requirements of this section and, except as provided in subsection (f)(5) of this section, comply with all other requirements of this section applicable to LQGs.

(C) An LQG shall not accumulate any particular quantity of hazardous oil and gas waste on-site for more than 90 days from the date that particular quantity was generated, unless an extension to such 90-day period has been granted in accordance with the provisions of subsection (f)(4)(D) of this section.

(D) The 90-day accumulation period specified in subsection (f)(4)(C) of this section may be extended an additional 30 days if the commission, at its sole discretion, determines that unforeseen, temporary, and uncontrollable circumstances require that hazardous oil and gas waste remain on-site for longer than 90 days.

(4) Accumulation in Containers at the Point of Generation.

(A) Notwithstanding the foregoing provisions of subsection (f) of this section, an LQG or SQG may accumulate in containers up to 55 gallons of hazardous oil and gas waste or a total of one quart of acute hazardous wastes listed in 40 CFR, §261.33(e) without having to manage such hazardous oil and gas waste in accordance with the accumulation time limits applicable to LQGs or SQGs or with the provisions of subsections (q) (relating to preparedness and prevention), (r) (relating to contingency plan and emergency procedures), (s) (relating to personnel training), (t) (relating to standards for use of containers), and (u) (standards for use of tank systems) of this section, provided that the requirements of subsection (f)(4)(B) of this section are met.

(B) All hazardous oil and gas waste subject to the exemption of subsection (f)(4)(A) of this section must be accumulated in containers that:

(i) are at a location that is:

(I) under the control of the generator; and

(II) at or near the point of generation;

(ii) meet the applicable requirements of 40 CFR, §§265.171, 265.172, and 265.173(a) (concerning container condition, compatibility of waste with container, and closing containers); and

(iii) are marked with the words "Hazardous Waste" or with other words that identify the contents of the containers.

(C) If the amount of hazardous waste accumulated on-site at or near the point of generation exceeds the maximum amount specified in subsection (f)(4)(A) of this section, the generator must, with respect to such excess waste, comply with all applicable provisions of this section within three days of the date that such maximum amount is exceeded.

(5) Episodic Generation. Except as otherwise provided in this paragraph, if a generator's classification varies from one month to another, the hazardous oil and gas waste generated during any particular month shall be managed in accordance with the requirements applicable to the generator's classification for that month.

(A) If hazardous oil and gas waste generated by a generator who is classified as a CESQG during a particular month is mixed with waste generated in a month during which the generator is considered an LQG, the mixture shall be managed in accordance with the standards applicable to LQGs.

(B) If hazardous oil and gas waste generated by a generator who is classified as a CESQG during a particular month is mixed with waste generated in a month during which the generator is considered an SQG, the mixture shall be managed in accordance with the standards applicable to SQGs.

(C) If hazardous oil and gas waste generated by a generator who is classified as an SQG during a particular month is mixed with waste generated in a month during which the generator is considered an LQG, the mixture shall be managed in accordance with the standards applicable to LQGs.

(g) Notification. A person who is considered an LQG or SQG under the provisions of this section must notify the commission of the activities of such person that are subject to the provisions of this section and obtain an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the commission. Such notification must be made upon the later of 90 days after the effective date of this section or within ten days of the date that the LQG or SQG becomes subject to the provisions of this section.

(h) Preparedness and Prevention.

(1) General. In addition to all other applicable requirements of this section, all generators of hazardous oil and gas waste shall employ reasonable and appropriate measures (considering the nature and location of the facility and the types and quantities of hazardous oil and gas waste maintained at the site) in the operation and maintenance of his or her generation site to minimize the possibility of a fire, explosion, or any unplanned sudden or non-sudden release of hazardous oil and gas wastes or hazardous oil and gas waste constituents to air, soil, or surface water that could threaten human health or the environment.

(2) LQGs and SQGs. LQGs and SQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart C (concerning preparedness and prevention).

(i) Contingency Plan and Emergency Procedures.

(1) LQGs. LQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart D (concerning contingency plan and emergency procedures).

(2) SQGs. SQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions of 40 CFR, §262.34(d)(5) (concerning emergency response).

(j) Personnel Training. LQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, §265.16 (concerning personnel training).

(k) Standards for Use of Containers.

(1) LQGs. LQGs accumulating hazardous oil and gas waste in containers must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart I (concerning use and management of containers);

(B) clearly mark each container being used to accumulate hazardous oil and gas waste on-site, in a manner and location visible for inspection, with the date accumulation of such hazardous oil and gas waste begins; and

(C) clearly label or mark each container being used to accumulate hazardous oil and gas waste on-site with the words "Hazardous Waste."

(2) SQGs. SQGs accumulating hazardous oil and gas waste in containers must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart I, except §265.176 (concerning distance from property lines);

(B) clearly mark each container being used to accumulate hazardous oil and gas waste on-site, in a manner and location visible for inspection, with the date accumulation of such hazardous oil and gas waste begins; and

(C) clearly label or mark each container being used to accumulate hazardous oil and gas waste on-site with the words "Hazardous Waste."

(3) CESQGs. The provisions of this paragraph apply to CESQGs only.

(A) Hazardous oil and gas waste generated by a CESQG may be mixed with non-hazardous waste even though the resultant mixture exceeds the quantity limitations of subsection (f)(1) of this section, unless the mixture exhibits any of the hazardous waste characteristics of the hazardous oil and gas waste in the mixture, as determined under subsection (e)(1)(D)(ii) of this section.

(B) If a CESQG's wastes are mixed with used oil, the mixture is subject to the requirements 40 CFR, Part 279 if the mixture is destined to be burned for energy recovery. Any material produced from such a mixture by processing, blending, or other treatment is also so regulated if it is destined to be burned for energy recovery.

(l) Standards for Use of Tank Systems.

(1) LQGs. LQGs accumulating hazardous oil and gas waste in tanks must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart J, except §265.197(c) and §265.200;

(B) comply with the provisions applicable to owners or operators of 40 CFR, §265.111 and §265.114 (concerning closure performance standards and disposal of contaminated equipment and media); and

(C) clearly label or mark each tank being used to accumulate hazardous oil and gas waste with the words "Hazardous Waste."

(2) SQGs. SQGs accumulating hazardous oil and gas waste in tanks must:

(A) comply with the provisions of 40 CFR, §265.201 (concerning accumulation of waste in tanks by small quantity generators); and

(B) clearly label or mark each tank being used to accumulate hazardous oil and gas waste with the words "Hazardous Waste."

(m) Disposition of Hazardous Oil and Gas Waste.

(1) On-site Treatment, Storage, Disposal, Recycling, and Reclamation. Except as otherwise specifically provided in this section, no person may treat, store, dispose of, recycle, or reclaim any hazardous oil and gas waste on-site.

(2) Transport to Authorized Facility.

(A) Except as otherwise specifically provided in this section and subject to all other applicable requirements of state or federal law, a generator of hazardous oil and gas waste must send his or her waste to one of the following categories of facilities for treatment, storage, disposal, recycling, or reclamation:

(i) an authorized recycling or reclamation facility;

(ii) an authorized treatment, storage, or disposal facility;

(iii) a facility located outside the United States, provided that the requirements of subsection (v)(1) of this section (relating to exports of hazardous waste) are met;

(iv) a transfer facility, provided that the requirements of subsection (w)(3) of this section are met;

(v) if the waste is generated by a CESQG, a facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste; or

(vi) if the waste is generated by a CESQG, a centralized waste collection facility (CWCF) that meets the requirements of subsection (m)(3) of this section.

(B) Notwithstanding any contrary provision of this subsection, hazardous oil and gas wastes may be treated or stored on-site in an elementary neutralization unit or a totally enclosed treatment facility. If a hazardous oil and gas waste that is ignitable under 40 CFR, §261.21 (other than DOO1 High TOC Subcategory wastes defined in 40 CFR, §268.42, Table 2) or that is corrosive under 40 CFR, §261.22 is being treated in an elementary neutralization unit or a wastewater treatment unit to remove the characteristic before land disposal, the owner or operator must comply with the requirements of 40 CFR, §264.17(b).

(C) While waste is being accumulated on-site in accordance with the provisions of subsection (f) of this section, a generator may treat hazardous oil and gas waste on-site in tanks or containers that comply with the applicable provisions of subsections (k) and (l) of this section.

(D) For purposes of §3.8(f)(1)(C)(vi) of this title (relating to Water Protection), the manifest for shipment of hazardous oil and gas waste to a designated facility (a facility designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section) shall be deemed commission authorization for disposal at a facility permitted by another agency or another state.

(3) Centralized Collection of Hazardous Oil and Gas Waste.

(A) Centralized Waste Collection Facility. Provided that the requirements of this paragraph are met, a person may maintain at a CWCF hazardous oil and gas waste that is generated:

(i) by that person; and

(ii) at sites where that person is considered a CESQG under the provisions of this section.

(B) Prior to receipt of oil and gas hazardous waste generated off-site, a person who operates a CWCF must register with the commission by filing with the commission a notice that includes the following information:

(i) a map showing the location of the CWCF and each individual hazardous oil and gas waste generation site that may contribute waste to the collection facility. In lieu a map, the person who operates the CWCF may provide to the commission the name and lease number, field name and number, or other identifying information acceptable to the commission, of the CWCF and each generation site that may contribute waste to the collection facility;

(ii) the person's P-5 operator number; and

(iii) the EPA ID number for the CWCF, if any.

(C) All hazardous oil and gas waste received at the CWCF must be kept in closed containers that are marked with the words "Hazardous Waste."

(D) A person operating a CWCF shall not maintain at the CWCF at any one time more than 5,000 kilograms of hazardous oil and gas waste or more than five quarts of any hazardous oil and gas waste that is listed in 40 CFR, §261.33(e) (acute hazardous waste).

(n) EPA ID Numbers.

(1) Generators. No LQG or SQG may transport or offer for transportation any hazardous oil and gas waste until such generator has obtained an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the commission.

(2) Transporters. No LQG or SQG may allow his or her hazardous oil and gas waste to be transported by a transporter that does not have an EPA ID number.

(3) Treatment, Storage, or Disposal Facilities. Except in the case of facilities specified in subsection (m)(2)(A)(iii), (vi), and (v) of this section, no LQG or SQG may send his or her hazardous oil and gas waste to a treatment, storage, or disposal facility unless that facility:

(A) is a designated facility as defined in this section; and

(B) has an EPA ID number.

(o) Manifests.

(1) General Requirements.

(A) Except as provided in subsection (o)(1)(E) of this section, each time an LQG or SQG transports hazardous oil and gas waste or offers hazardous oil and gas waste for transportation to an authorized facility, such generator must prepare a manifest form. If the waste was generated in the State of Texas and is being transferred to an authorized facility located within the State of Texas, the generator shall use the form prescribed by the TCEQ. If the authorized facility is located outside the State of Texas, the generator must refer to subsection (o)(2) of this section to determine which manifest form to use.

(B) The generator must specify on the manifest one authorized facility to handle the hazardous oil and gas waste described on the manifest (the "primary designated facility").

(C) The generator may also specify on the manifest one alternate authorized facility to handle the hazardous oil and gas waste (the "alternate designated facility") in the event an emergency prevents delivery of the hazardous oil and gas waste to the primary designated facility.

(D) If the transporter is unable to deliver the hazardous oil and gas waste to the primary designated facility or the alternate designated facility, the generator must either specify another authorized facility to which the hazardous oil and gas waste can be delivered or instruct the transporter to return the hazardous oil and gas waste to the generator. If the generator specifies another authorized facility to which the hazardous oil and gas waste can be delivered, the generator shall instruct the transporter to revise the manifest to show this facility as the designated facility (see subsection (w)(6) of this section relating to transporter's inability to deliver waste).

(E) An SQG is not required to comply with the provisions of this subsection (relating to manifests) if:

(i) the SQG's hazardous oil and gas waste is reclaimed under a contractual agreement (the "hazardous waste reclamation agreement") pursuant to which:

(I) the type of hazardous oil and gas waste and frequency of shipments are specified in the agreement; and

(II) the vehicle used to transport the hazardous oil and gas waste to the hazardous waste reclamation facility and to deliver regenerated material back to the generator is owned and operated by the hazardous waste reclamation facility;

(ii) the SQG maintains a copy of the hazardous waste reclamation agreement in his or her files for a period of at least three years after termination or expiration of the reclamation agreement; and

(iii) the SQG complies with the provisions of 40 CFR, §268.7(a)(10) (concerning land ban wastes subject to tolling agreements) if the waste is determined to be prohibited from land disposal under subsection (e)(2) of this section (relating to land ban wastes).

(2) Manifests Required for Out-of-State Domestic Shipments.

(A) If the hazardous oil and gas waste was generated within the United States, but outside the State of Texas, and is being transported to an authorized facility located within the State of Texas, the generator must use the form prescribed by the TCEQ.

(B) If the hazardous oil and gas waste was generated within the State of Texas and is being transported to an authorized facility located within the United States but outside the State of Texas (the "consignment state"), the manifest specified by the consignment state shall be used. If the consignment state does not specify a particular manifest form for use, then the generator shall use the form prescribed by the TCEQ.

(3) Number of Copies. The manifest must consist of at least the number of copies that will provide the generator, each transporter, and the owner or operator of the designated facility with one copy each for their records and one additional copy to be returned to the generator by the owner or operator of the designated facility to which the waste was delivered (in accordance with the provisions of 40 CFR, §264.71 and §265.71, or state equivalent).

(4) Use of the Manifest.

(A) The generator must:

(i) sign the manifest certification by hand;

(ii) obtain the handwritten signature of the initial transporter and date of acceptance of the shipment by the initial transporter on the manifest;

(iii) retain one copy of the manifest signed by the initial transporter until the copy signed by the operator of the designated facility (in accordance with 40 Code of Federal Regulations §264.71, §265.71, or state equivalent) is received;

(iv) give the transporter the remaining copies of the manifest; and

(v) obtain one copy of the manifest, signed by the owner or operator of the designated facility that received the hazardous oil and gas waste, and retain that copy for three years from the date the hazardous oil and gas waste was accepted for shipment by the initial transporter.

(B) For shipments of hazardous oil and gas waste within the United States solely by water (bulk shipments only), the generator must send three copies of the manifest, dated and signed in accordance with the provisions of paragraph (4)(A) of this subsection (relating to use of the manifest), to either:

(i) the owner or operator of the designated facility; or

(ii) if exported by water, the last water transporter expected to handle the hazardous oil and gas waste in the United States. Copies of the manifest are not required for each transporter.

(C) For rail shipments of hazardous oil and gas waste within the United States that originate at the generation site, the generator must send at least three copies of the manifest, dated and signed in accordance with the provisions of paragraph (4)(A) of this subsection (relating to use of the manifest), to:

(i) the next non-rail transporter, if any;

(ii) the designated facility, if transported solely by rail; or

(iii) if exported by rail, the last rail transporter expected to handle the hazardous oil and gas waste in the United States.

(D) For shipments of hazardous oil and gas waste to a designated facility located outside the State of Texas and in an authorized state that has not yet obtained authorization from the EPA to regulate that particular waste as hazardous, the generator must determine that the owner or operator of the designated facility agrees to sign and return the manifest to the generator (in accordance with the applicable provisions of 40 CFR, §264.71 or §265.71), and that any out-of-state transporter agrees to comply with the applicable requirements of subsection (w)(4) of this section (relating to manifest requirements for transporters).

(p) Packaging. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, an LQG or SQG must package the hazardous oil and gas waste in accordance with the applicable DOT packaging regulations set out in 49 CFR, Parts 173, 178, and 179.

(q) Labeling. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must label each package that contains hazardous oil and gas waste in accordance with the applicable DOT regulations set out in 49 CFR, Part 172.

(r) Marking.

(1) General. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must mark each package that contains hazardous oil and gas waste in accordance with the applicable DOT regulations set out in 49 CFR, Part 172.

(2) Non-Bulk Packaging. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must mark each package that contains hazardous oil and gas waste and is of a size specified in 40 CFR, §262.32(b) (110 gallons or less), with the following words and information. Such words and information must be displayed in accordance with the applicable requirements of 49 CFR, 172.304. The generator must include his or her name and address and the manifest document number in the appropriate space: HAZARDOUS WASTE--Federal Law Prohibits Improper Disposal. If found, contact the nearest police or public safety authority or the U.S.

Environmental Protection Agency, Generator's Name and Address: ____________________ Manifest Document Number: ____________________

(s) Placarding. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must placard the vehicle or vehicles used to transport such hazardous oil and gas waste, or offer to the initial transporter the appropriate placards. Appropriate placards shall be determined according to DOT regulations set out in 49 CFR, Part 172, Subpart F.

(t) Recordkeeping.

(1) Waste Determination. Each LQG and SQG shall keep records of any and all test results, waste analyses, or other determinations made in accordance with subsection (e) of this section (relating to hazardous waste determination), for at least three years from the date that the waste was last sent to an authorized facility.

(2) Annual Reports. A copy of all reports required in subsection (u)(1) of this section (relating to annual reports), shall be retained by the generator for a period of at least three years from the due date of the report.

(3) Exception Reports. A copy of all reports required under subsection (u)(2) of this section (relating to exception reports), shall be retained by the generator for a period of at least three years from the due date of the report.

(4) Inspection Reports. A copy of each inspection report required under this section shall be retained by the generator for a period of at least three years from the due date of the report.

(5) Extension. The periods of record retention specified in subsection (t)(1) - (4) of this section are extended automatically during the course of any unresolved enforcement action regarding the regulated activity or upon request by the commission.

(u) Reporting.

(1) Annual Reports. Any generator who is classified as an LQG or SQG during any calendar month of a calendar year shall prepare and submit a single copy of an annual report to the commission on the annual reporting form prescribed by the commission, Form H-21. The report shall be filed on or before the first day of March of the following calendar year and shall be accompanied by the fee assessed under the provisions of subsection (z) of this section. The annual report shall contain a certification signed by the generator. The annual report shall cover activities occurring at the generation site during the month(s) of the reporting year that the site was classified as a small or large quantity generation site, and shall include the following information:

(A) the name of the generator followed by the generator's P-5 operator number in parentheses, the EPA

ID number for the generation site, and the address of the generation site or other site-identifying information (such as the lease number, unit number, or T-4 number (in the case of pipelines));

(B) the calendar year covered by the report;

(C) the name, EPA ID number, if any, and address for each authorized facility within the United States to which hazardous oil and gas waste was shipped during the year;

(D) the name and EPA ID number of each transporter used during the year for shipments to an authorized facility within the United States;

(E) a description, EPA hazardous waste number (from 40 CFR, Part 261, Subpart C or D), United States DOT hazard class, and quantity of each hazardous oil and gas waste shipped to an authorized facility within the United States. This information must be listed by the EPA ID number of each facility to which hazardous oil and gas waste was shipped. If the waste was shipped to an authorized facility that does not have an EPA ID number, the type of facility (reclamation or recycling) must be designated on the report;

(F) a description of the efforts undertaken during the year to reduce the volume and toxicity of hazardous oil and gas waste generated; and

(G) a description of the changes in volume and toxicity of hazardous oil and gas waste actually achieved during the year in comparison to previous years, to the extent such information is available.

(2) Exception Reports.

(A) An LQG who does not receive a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 35 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment must contact the transporter and, if necessary, the owner or operator of the designated facility to determine the status of the hazardous oil and gas waste shipment.

(B) An LQG must submit an exception report to the commission if he or she has not received a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 45 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment. The exception report must include:

(i) a legible copy of the manifest for that shipment of hazardous oil and gas waste for which the generator does not have confirmation of delivery; and

(ii) a letter signed by the generator explaining the efforts taken to locate the hazardous oil and gas waste and the results of those efforts.

(C) An SQG who does not receive confirmation of delivery of hazardous oil and gas waste by receipt of a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 60 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment, must submit to the commission an exception report. The exception report must include:

(i) a legible copy of the manifest for which the generator does not have confirmation of delivery; and

(ii) a notation, either typed or handwritten, indicating that the generator has not received confirmation of delivery of the shipment to the designated facility.

(D) In the case of interstate shipments of hazardous oil and gas waste for which a manifest has not been returned within 45 days of acceptance of the hazardous oil and gas waste for shipment by the initial transporter, an LQG or SQG shall notify the appropriate regulatory agency of the state in which the designated facility is located, and the appropriate regulatory agency of each state in which the shipment may have been delivered, that the manifest has not been received. If a state required to be notified under this section has not received interim or final authorization pursuant to the RCRA, the LQG or SQG shall notify the administrator that the manifest has not been returned.

(3) Additional Reporting. The commission may require any generator of hazardous oil and gas waste to furnish additional reports concerning the quantities and disposition of hazardous oil and gas waste generated.

(v) Additional Requirements Applicable to International Shipments.

(1) Exports.

(A) Any person who exports hazardous oil and gas waste to a foreign country must comply with the requirements of 40 CFR, Part 262, Subpart E.

(B) Primary exporters of hazardous oil and gas waste generated within the State of Texas must submit to the commission a copy of the annual report submitted to the administrator in compliance with 40 CFR, §262.56.

(2) Imports. Any person who imports hazardous oil and gas waste generated outside the United States into the State of Texas shall be considered the generator of such hazardous oil and gas waste for the purposes of this section. Such person must comply with the applicable provisions of this section, except that:

(A) the name and address of the foreign generator and the importer's name, address, and EPA ID number shall be substituted on the manifest in place of the generator's name, address, and EPA ID number;

(B) the importer or the importer's agent must sign and date the certification and obtain the signature of the initial transporter in place of the generator's certification statement on the manifest; and

(C) the importer shall use the manifest form prescribed by the TCEQ.

(w) Standards Applicable to Transporters of Hazardous Oil and Gas Waste. The following standards apply to persons who transport hazardous oil and gas waste generated by LQGs and SQGs. The requirements of this subsection do not apply in the case of hazardous oil and gas waste generated by CESQGs.

(1) Scope.

(A) This subsection establishes standards for persons transporting hazardous oil and gas waste from the generation site to any designated facility. The provisions of this section do not apply with respect to on-site movements of hazardous oil and gas waste.

(B) In addition to the provisions of this subsection, a transporter must comply with standards applicable to generators of hazardous oil and gas waste if he or she mixes hazardous oil and gas wastes of different DOT shipping descriptions by placing them into a single container. If a transporter mixes a hazardous oil and gas waste with a hazardous waste that is not considered a hazardous oil and gas waste, the transporter must comply with the standards applicable to generators of hazardous wastes found at Title 30, Texas Administrative Code, Chapter 335, Subchapter C (the TCEQ's standards for generators of hazardous waste).

(2) Permits and EPA ID Numbers. No transporter may transport hazardous oil and gas waste unless he or she has an EPA ID number. The transporter may obtain an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the appropriate regulatory entity (either EPA, TCEQ, the commission, or another state).

(3) Transfer Facility Requirements. No transporter may store manifested hazardous oil and gas waste at a transfer facility for any period of time unless:

(A) the hazardous oil and gas waste is packaged in containers that meet the requirements of subsection (p) of this section (relating to packaging); and

(B) the hazardous oil and gas waste is stored at the transfer facility for no longer than ten days.

(4) Manifest Requirements.

(A) A transporter may not accept hazardous oil and gas waste for shipment from a generator unless it is accompanied by a manifest signed in accordance with the provisions of subsection (o)(4) of this section (relating to use of the manifest).

(B) Before transporting hazardous oil and gas waste, the transporter must sign and date the manifest acknowledging acceptance of the hazardous oil and gas waste from the generator. The transporter must return a signed copy of the manifest to the generator before leaving the generation site.

(C) The transporter must ensure that the manifest accompanies the shipment of hazardous oil and gas waste. In the case of exports, the transporter must ensure that a copy of the EPA Acknowledgment of Consent is attached to the manifest.

(D) A transporter may not accept hazardous oil and gas waste for export from a primary exporter or other person if:

(i) the transporter knows that the shipment does not conform to the EPA Acknowledgment of Consent; or

(ii) except in the case of shipments by rail, an EPA Acknowledgment of Consent is not attached to the manifest (or shipping paper in the case of exports by water (bulk shipment)).

(E) A transporter who delivers a hazardous oil and gas waste to another transporter or to the designated facility must:

(i) obtain the date of delivery and the handwritten signature of the other transporter or of the owner or operator of the designated facility on the manifest;

(ii) retain one copy of the manifest in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping); and

(iii) give the remaining copies of the manifest to the accepting transporter or owner or operator of the designated facility.

(F) The requirements of subsection (w)(4)(C), (D), (E), and (G) of this section do not apply to water (bulk shipment) transporters if:

(i) the hazardous oil and gas waste is delivered by water (bulk shipment) to the designated facility;

(ii) a shipping paper containing all the information required on the manifest (excluding the EPA ID numbers, generator certification, and signatures) and, for exports, an EPA Acknowledgment of Consent, accompanies the hazardous oil and gas waste;

(iii) the delivering transporter obtains the date of delivery and handwritten signature of the owner or operator of the designated facility on either the manifest or the shipping paper;

(iv) the person delivering the hazardous oil and gas waste to the initial water (bulk shipment) transporter obtains the date of delivery and signature of the water (bulk shipment) transporter on the manifest and forwards it to the designated facility; and

(v) a copy of the shipping paper or manifest is retained by each water (bulk shipment) transporter in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping).

(G) For shipments involving rail transportation, the requirements of subsection (w)(4)(C), (D), (E), and (F) of this section do not apply and the following requirements do apply:

(i) when accepting hazardous oil and gas waste from a non-rail transporter, the initial rail transporter must:

(I) sign and date the manifest acknowledging acceptance of the hazardous oil and gas waste;

(II) return a signed copy of the manifest to the non-rail transporter;

(III) forward at least three copies of the manifest to:

(-a-) the next non-rail transporter, if any;

(-b-) the designated facility, if the shipment is delivered to that facility by rail; or

(-c-) the last rail transporter designated to handle the hazardous oil and gas waste in the United States; and

(IV) retain one copy of the manifest and rail shipping paper in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(ii) rail transporters must ensure that a shipping paper containing all the information required on the manifest (excluding the EPA ID numbers, generator certification, and signatures) and, for exports, an EPA Acknowledgment of Consent, accompanies the hazardous oil and gas waste at all times;

(iii) when delivering hazardous oil and gas waste to the designated facility, a rail transporter must:

(I) obtain the date of delivery and handwritten signature of the owner or operator of the designated facility on the manifest or the shipping paper (if the manifest has not been received by the facility); and

(II) retain a copy of the manifest or signed shipping paper in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(iv) when delivering hazardous oil and gas waste to a non-rail transporter, a rail transporter must:

(I) obtain the date of delivery and the handwritten signature of the next non-rail transporter on the manifest; and

(II) retain a copy of the manifest in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(v) before accepting hazardous oil and gas waste from a rail transporter, a non-rail transporter must sign and date the manifest and provide a copy to the rail transporter.

(H) Transporters who transport hazardous oil and gas waste out of the United States must:

(i) indicate on the manifest the date the hazardous oil and gas waste left the United States;

(ii) sign the manifest and retain one copy in accordance with the provisions of subsection (v)(1) of this section;

(iii) return a signed copy of the manifest to the generator; and

(iv) give a copy of the manifest to a United States customs official at the point of departure from the United States.

(I) A transporter accepting hazardous oil and gas waste for shipment from an SQG need not comply with the requirements of subsection (w)(4) and (7) of this section provided that:

(i) the hazardous oil and gas waste is being transported pursuant to a reclamation agreement that meets the requirements of subsection (o)(1)(E) of this section;

(ii) the transporter records, on a log or shipping paper, the following information for each shipment:

(I) the name, address, and EPA ID number of the generator of the hazardous oil and gas waste;

(II) the quantity of hazardous oil and gas waste accepted;

(III) all DOT required shipping information;

(IV) the date the hazardous oil and gas waste is accepted;

(iii) the transporter carries this record when transporting the hazardous oil and gas waste to the reclamation facility; and

(iv) the transporter retains these records for a period of at least three years after termination or expiration of the agreement.

(5) Delivery of Waste. The transporter must deliver the entire quantity of hazardous oil and gas waste accepted from a generator or a transporter to:

(A) the primary designated facility;

(B) the alternate designated facility, if the hazardous oil and gas waste cannot be delivered to the primary designated facility because an emergency prevents delivery;

(C) the next designated transporter; or

(D) for exports, the location designated in the EPA Acknowledgment of Consent.

(6) Inability to Deliver Waste. If the hazardous oil and gas waste cannot be delivered as provided in subsection (w)(5) of this section the transporter must contact the generator for further directions and must revise the manifest according to the generator's instructions.

(7) Recordkeeping.

(A) A transporter of hazardous oil and gas waste must keep a copy of the manifest signed by the generator, himself or herself, and the next transporter or the owner or operator of the designated facility for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(B) For shipments delivered to the designated facility by water (bulk shipment), each water (bulk shipment) transporter must retain a copy of the shipping paper containing all the information required in 40 CFR, §263.20(e)(2) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(C) For shipments of hazardous oil and gas waste by rail within the United States:

(i) the initial rail transporter must keep a copy of the manifest and shipping paper with all the information required in 40 CFR, §263.20(f)(2) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter; and

(ii) the final rail transporter must keep a copy of the signed manifest (or the shipping paper if signed by the designated facility in lieu of the manifest) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(D) A transporter who transports hazardous oil and gas waste out of the United States must keep, for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter, a copy of the manifest indicating that the hazardous oil and gas waste left the United States.

(E) The periods of retention referred to in subsection (w)(7) of this section are extended automatically during the course of any unresolved enforcement action regarding the regulated activity or upon request by the commission.

(x) Discharges.

(1) Reporting Requirements.

(A) Commission. A person subject to regulation under this section shall immediately notify the commission upon discovery of any discharge in which a reportable quantity of a hazardous oil and gas waste is discharged. Such notification shall be made by contacting the appropriate commission district office.

(B) Federal. Persons subject to regulation under this section shall comply with applicable reporting requirements of 40 CFR, Parts 117, 263, and 302.

(2) Initial Response.

(A) Immediate Action. Upon discovery of a discharge of hazardous oil and gas waste, the generator or transporter must take appropriate immediate action to protect human health and the environment (e.g., notify local authorities, where appropriate, and dike the discharge area).

(B) Permitting Exemption. The prohibition of on-site treatment, storage, disposal, recycling, or reclamation activities in subsection (m)(1) of this section does not apply to activities performed by a person engaged in treatment or containment activities during immediate response to a discharge of hazardous oil and gas waste; an imminent and substantial threat of a discharge of hazardous oil and gas waste; or a discharge of a substance which, when discharged, would become a hazardous oil and gas waste, provided that:

(i) any hazardous oil and gas waste associated with such discharge is managed in accordance with applicable provisions of subsections (h) (relating to preparedness and prevention), (i) (relating to personnel training), (k) (relating to standards for use of containers), and (l) (standards for use of tank systems) of this section; and

(ii) the applicable discharge reporting requirements of subsection (x) of this section are complied with.

(C) Continued Measures. The provisions of subparagraph (B) of this paragraph do not apply to activities that continue or are initiated after the immediate response is over. Such activities are subject to all applicable requirements of this section.

(3) Discharge Clean Up.

(A) The generator or transporter shall recover as much as of the spilled material as can be recovered by ordinary physical means as soon as possible after discovery of the spill.

(B) The generator or transporter shall clean up the site at which the discharge occurred to background levels as soon as reasonably possible. As an alternative to clean-up to background levels, the generator or transporter must take such action as may be required or approved by the commission so that the hazardous oil and gas waste discharge no longer presents a hazard to human health or the environment, taking into consideration the geology and hydrology of the discharge site, the nature and quantity of the hazardous oil and gas waste discharged, and the present and anticipated future use of the discharge site.

(C) If an official (state or local government or a federal agency) acting within the scope of his or her official responsibilities determines that immediate removal of the hazardous oil and gas waste associated with a discharge is necessary to protect human health or the environment, that official may authorize the removal of the hazardous oil and gas waste by transporters who do not have EPA ID numbers and without the preparation of a manifest.

(y) Emergency Permits.

(1) General. Notwithstanding any other provision of this section, the commission may authorize by emergency permit the treatment, storage, or disposal of hazardous oil and gas waste where the commission finds that a discharge of hazardous oil and gas waste poses a danger to life or property.

(2) Requirements. An emergency permit:

(A) may be oral or written. If oral, a written permit must be issued within five days of issuance of the oral permit;

(B) shall have a term of not more than 90 days;

(C) shall clearly specify the manner and location of authorized treatment, storage, and disposal activities;

(D) may be terminated by the commission without notice if the commission determines that termination is appropriate to protect human health and the environment;

(E) shall incorporate, to the extent possible and not inconsistent with the emergency situation, all applicable requirements of 40 CFR, Parts 264, 266, and 270; and

(F) shall be accompanied by a public notice published in a daily or local newspaper of general circulation in the area affected by the activity and broadcast over local radio stations. The notice shall include:

(i) the name and address of the office granting the emergency authorization;

(ii) the name and location at which the permitted activities will take place;

(iii) a brief description of the hazardous oil and gas wastes involved;

(iv) a brief description of the actions authorized and reasons for authorization of such actions; and

(v) the duration of the emergency permit.

(z) Fees.

(1) Base fee.

(A) Except as provided in subparagraph (B) of this paragraph:

(i) each generator who is classified as an LQG during any calendar month of a calendar year shall pay to the commission a base annual fee for generation of hazardous oil and gas waste of $1,000;

(ii) each generator who is not classified as an LQG during any calendar month of a calendar year, but is classified as an SQG during a calendar month of that calendar year, shall pay to the commission a base annual fee for generation of hazardous oil and gas waste of $200; and

(iii) no annual fee for generation of hazardous oil and gas waste shall be assessed against a generator who is classified as a CESQG during all months of the entire calendar year in which he or she generates hazardous oil and gas waste.

(B) For purposes of determining the base fee as provided in subparagraph (A) of this paragraph, generator classification shall be determined after excluding quantities of hazardous oil and gas waste generated in connection with a spill or discharge, including contaminated soil, media, and debris, if, within 30 days after discovery of such spill or discharge, the generator files a one-page typewritten report with the commission that describes:

(i) the nature and quantity of spilled or discharged material;

(ii) the reason for or cause of the spill or discharge; and

(iii) the steps that have been or will be taken by the generator to minimize the likelihood of a similar spill or discharge at that site.

(2) Additional fee. The base annual fee determined according to the provisions of paragraph (1) of this subsection shall be doubled if less than 50% of the hazardous oil and gas wastes generated at the site during the entire calendar year are recycled, reused or reclaimed. For purposes of calculating the percentage of hazardous oil and gas wastes that are recycled, reused, or reclaimed, hazardous oil and gas wastes excluded from regulation under this section by the provisions of subsection (e)(3)(B)(i) - (iii) of this section (relating to exclusions and exemptions from hazardous oil and gas waste classification) and subsection (m)(2)(B) of this section (relating to elementary neutralization units, totally enclosed treatment facilities, and wastewater treatment units) shall be included in the quantity of hazardous oil and gas waste recycled, reused, or reclaimed. The wastes excluded from regulation under this section under the provisions of subsections (e)(3)(B)(i) - (iii) and (m)(2)(B) of this section shall not be included when calculating the quantity of waste generated for purposes of determining generator classification.

(3) Fee payment. The base fee and any additional fee assessed under this subsection shall be paid to the commission on or before the first day of March of the year following the calendar year in which the waste was generated. Fees assessed under this subsection shall be tendered to the commission with the annual report (see subsection (u)(1) of this section).

(aa) Penalties. A person subject to regulation under this section is subject to the penalties prescribed in the Texas Natural Resources Code if such person does not comply with the requirements of this section.

(bb) Federal Regulations. All references to the Code of Federal Regulations (CFR) in this section are references to the 1994 edition of the Code, as amended through November 7, 1995. The following federal regulations are adopted by reference and copies can be obtained at the William B. Travis Building, 1701 North Congress, Austin, Texas 78711: 40 CFR, Parts 116, 117, 124, 264, 266, 268, 270, 271, 279, and 302; 40 CFR, Part 261, Subparts A, C, and D; 40 CFR, Part 262, Subparts B and E; 40 CFR, Part 265, Subparts C, D, I, and J (except §265.197(c) and §265.200); 40 CFR, §§260.21, 260.22, 262.34(d)(5), 265.16, 265.111, 265.114, and 265.201; 49 CFR, Parts 172, 173, 178, and 179; and 49 CFR, §171.15 and §171.16. Words and terms used in the federal regulations adopted by reference shall have the meanings given in the federal regulations adopted by reference or in 40 CFR, §260.10, unless otherwise specified. Where the term "State Director" is applicable in the federal regulations adopted by reference, it should be interpreted to mean "commission."

Source Note: The provisions of this §3.98 adopted to be effective April 1, 1996, 20 TexReg 9423; amended to be effective May 4, 1999, 24 TexReg 3313; amended to be effective September 10, 2001, 26 TexReg 6870; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.99 Cathodic Protection Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cathodic protection well--Any well drilled for the purpose of installing one or more anodes to prevent corrosion of a facility associated with the production of oil, gas, or geothermal resources, such as a well casing, storage and separation facility, or pipeline.

(2) The director of the commissions's Oil and Gas Division, or the director's delegate, may administratively approve or deny a request for certification.

(3) If the director of the commission's Oil and Gas Division or the director's delegate denies the request, the operator may request a hearing by filing such a request in writing within 15 days after the postmarked date of the notice of the administrative denial.

(4) If the operator fails to appear at the hearing without good cause, the request for certification shall be dismissed.

(5) Filings and correspondence concerning the application for certification shall be addressed to the Railroad Commission, P.O. Box 12967, Austin, Texas 78711-2967, Attention: Permitting/Production Services Section.

(e) Application to the Comptroller. After the commission issues the certification provided for in subsection (d) of this section, the operator may apply to the Comptroller of Public Accounts to receive the tax exemption.

(f) Termination of Authorization to Release Gas. On the date the commission issues the certification provided for in subsection (d) of this section, either by administrative action or by commission order, the volume of casinghead gas authorized to be released into the air as an exception obtained pursuant to §3.32(h) of this title shall be reduced to the volume of casinghead gas not subject to the certification. If all of the volume of casinghead gas authorized to be released under an exception is certified for purposes of the tax exemption, the exception shall no longer apply, and shall automatically terminate as of the date of certification.

Source Note: The provisions of this §3.103 adopted to be effective August 4, 1998, 23 TexReg 7770.

§3.106 Sour Gas Pipeline Facility Construction Permit

(a) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--The owner or occupant of real property located in the area of influence of the proposed route of a sour gas pipeline facility. If the final proposed route of the pipeline is unknown at the time of application, then an affected person is any person who owns or occupies real property located within the area of influence associated with any possible pipeline route identified by the applicant. For purposes of this definition, the owner shall be the owner of record as of the final day to protest an application. The occupant shall be the occupant as of the final day to protest an application.

(2) Applicant--A person who has filed an application for a permit to construct a sour gas pipeline facility, or a representative of that person.

(3) Application--Application for a Permit to Construct a Sour Gas Pipeline Facility, and all required attachments.

(4) Area of influence--Area along a sour gas pipeline facility represented by all possible areas of exposure using the 100 ppm radius.

(5) Construction of a facility--Any activity conducted during the initial construction of a pipeline including the removal of earth, vegetation, or obstructions along the proposed pipeline right-of-way. The term does not include:

(A) surveying or acquiring the right-of-way;

(B) clearing the right-of-way with the consent of the owner;

(C) repairing or maintaining an existing sour gas pipeline facility; or

(D) installing valves or meters or other devices or fabrications on an existing pipeline if such devices or fabrication do not result in an increase in the area of influence.

(6) Extension of a sour gas pipeline facility--An addition to an operating sour gas pipeline facility regardless of ownership of the addition.

(7) Nominal pipe size--The industry convention for naming pipe. Six inch nominal size pipe corresponds to pipe with an approximate inner diameter of six inches. The actual inner diameter varies based on the wall thickness of the pipe.

(8) Person--An individual, partnership, firm, corporation, joint venture, trust, association, or any other business entity, a state agency or institution, county, municipality, school district, or other governmental subdivision.

(9) Preliminary contingency plan--A contingency plan containing all of the elements required for a contingency plan under §3.36 of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas), except that:

(A) the plan need not contain the list of names and telephone numbers of residents within the area of influence if required under §3.36(c)(9)(I) of this section. In lieu of this list of names and telephone numbers, the plan shall contain a detailed explanation of the manner in which the names and telephone numbers of residents within the area of influence will be compiled prior to commencement of operations;

(B) the plat detailing the area of influence may be:

(i) the detailed plat required under §3.36(c)(9)(H);

(ii) a plat containing the information required under §3.36(c)(9)(H), that identifies residential, business, and industrial areas with an estimate of the number of people that may be within any such areas; or

(iii) one or more aerial photographs covering the area and providing the information required under §3.36(c)(9)(H); and

(C) a fixed pipeline route need not be specified in the preliminary plan provided the preliminary plan identifies the boundaries of the area within which the pipeline will be constructed and provided that all public notices of the application required under this section note such boundaries and identify the potential area of influence as the total area encompassed by the area of influence associated with all possible pipeline routes.

(10) Sour gas pipeline facility--A pipeline and ancillary equipment that:

(A) contains a concentration of 100 parts per million or more of hydrogen sulfide;

(B) is located outside the tract of production; and

(C) is subject to the requirements of §3.36 of this title.

(11) Tract of production--The surface area which overlies the area encompassed by a mineral lease or unit from which oil, gas, or other minerals are produced if such area is treated by the Oil and Gas Division of the commission as a single tract.

(12) 100 ppm radius--The 100 parts per million radius of exposure as calculated in §3.36(c)(1) - (3) of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas) for the sour gas pipeline facility.

(b) Permit Required; Exceptions. No person may commence construction of a facility within this State without a permit if the facility is initially used as a sour gas pipeline facility except for the following:

(1) an extension of an existing sour gas pipeline facility that at the time of construction of the extension is in compliance with §3.36 of this title (relating to oil, gas, or geothermal resource operation in a hydrogen sulfide area) if:

(A) the extension is not longer than five miles;

(B) the nominal pipe size is not larger than six inches; and

(C) the operator causes to be delivered to the Safety Division written notice of construction of the extension not later than 24 hours before the start of construction;

(2) a new gathering system that operates at a working pressure of less than 50 pounds per square inch gauge;

(3) an extension of a gathering system which operates at a working pressure of less than 50 pounds per square inch gauge;

(4) an interstate gas pipeline facility, as defined by 49 U.S.C. §60101, that is used for the transportation of sour gas; or

(5) replacement of all or part of a sour gas pipeline facility if the area of influence of the replaced portion of the facility does not increase so as to include a public area, as defined in §3.36(b)(5) of this title, not included in the area of influence of the portion of the replaced sour gas pipeline facility.

(c) Filing and Assignment of Docket Number. Upon filing of an application with the Oil and Gas Division, staff will assign a docket number to the application and will notify the applicant of the assigned docket number. Staff will also assign and provide a docket number to a person who submits a notice of intent to file an application.

(d) Application. A complete application consists of:

(1) a properly completed application Form PS-79, with the original signature, in ink, of the applicant;

(2) if applicant desires notification under subsection (h)(1) by electronic mail, a written request for electronic mail notification and the applicant's electronic mail address;

(3) a plat which meets the requirements of subsection (f)(4) of this section and identifies the boundaries of surveys and blocks or sections as appropriate within the area of influence;

(4) a copy of the applicant's Application for Permit to Operate a Pipeline, Form T-4, if applicable, including all attachments; and

(5) a copy of the completed application for a Statewide Rule 36 Certificate of Compliance, Form H-9, including any attachment required under §3.36 of this title. A preliminary contingency plan may be filed in lieu of a contingency plan if required under §3.36 of this title.

(e) Notice.

(1) For each county that contains all or part of the area of influence of a proposed sour gas pipeline facility, the applicant shall:

(A) cause to be delivered to the county clerk no later than the first date of publication in that county a copy of the items described in subsection (d)(1) - (3) of this section;

(B) publish notice of its application in a newspaper of general circulation in each county that contains all or a portion of the area of influence of the proposed sour gas pipeline facility. Such notice shall meet the requirements of subsection (f) of this section and be published in a section of the newspaper containing news items of state or local interest.

(2) Final action may not be taken on any application under this section until proof of notice, evidenced as follows, is provided:

(A) a return receipt from each county clerk with whom an application form and plat is required to be filed pursuant to paragraph (1) of this subsection; and

(B) the full page or pages of the newspaper containing the published notice required under paragraph (2) of this subsection including the name of the paper, the date the notice was published, and the page number.

(f) The published notice of application shall be at least three inches by five inches in size, exclusive of the plat, and shall contain the following:

(1) the name, business address, and telephone number of the applicant and of the applicant's authorized representative, if any;

(2) a description of the geographic location of the sour gas pipeline facility and the area of influence, to the extent not clearly identified in the plat required to be published in subsection (f)(4) of this section;

(3) the following statement, completed as appropriate: "This proposed pipeline facility will transport sour gas that contains 100 parts per million, or more, of hydrogen sulfide. A copy of application forms and a map showing the location of the pipeline is available for public inspection at the offices of the (insert County name) County Clerk, located at the following address: (insert address of County Clerk). Any owner or occupant of land located within the area of influence of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to the application (by docket number if available) and stating their desire to protest to: Docket Services, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967. Protests shall be in writing and received by Docket Services not later than (specify 30th day after the first date notice of the application is to be published). The letter shall include the name, address, and telephone number of every person on whose behalf the protest is filed and shall state the reasons each such person believes that he or she is the owner or occupant of property within the area of influence of the proposed pipeline facility. It is recommended that a copy of this notice be included with the letter."; and

(4) a plat identifying:

(A) the location of the pipeline facility;

(B) area of influence;

(C) north arrow;

(D) scale;

(E) geographic subdivisions appropriate for the scale; and

(F) by inset or otherwise, landmarks or other features such as roads and highways in relation to the proposed route of the sour gas pipeline facility. These landmarks or other features shall be of sufficient detail to allow a person to reasonably ascertain whether an owned or occupied property that is within the area of influence of the proposed sour gas pipeline facility. Examples of acceptable plats are included in this subsection.

NOTICE OF APPLICATION FOR PIPELINE PERMIT

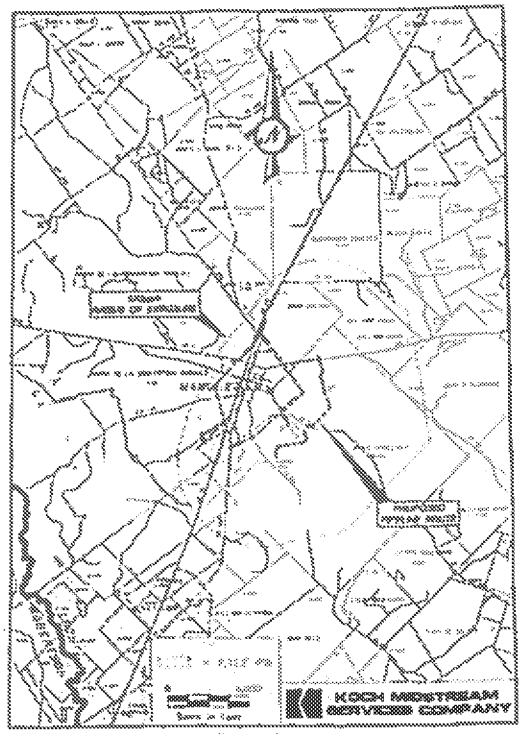
Koch Midstream Services Company, 606 S. Shelby St., Carthage, Texas 75633, has applied to the Railroad Commission of Texas for a permit to construct a 2.85 miles buried pipeline in Leon County, Texas, to gather natural gas containing hydrogen sulfide (Sour Gas). In the event of a leak, the radius of exposure of hydrogen sulfide for 100 parts per million (ppm) could extend 7113 feet on either side of the pipeline based on methods outlined in the 16 Texas Administration Code 3.36(2). The radius of exposure included parts of U.S. Hwy. 79 and extends northeasterly thru Marquez city limits. The applicant proposes to construct pipeline beginning 7,836 ft. southeasterly of a point of intersection of U.S. Hwy. 79 and State Hwy. 7 extending northeasterly 2.05 miles ending 5,808 ft. of a point of intersection of U. S. Hwy. 79 and State Hwy. 7. The city limits of Marquez are shown on the plat. The southwestern end of the pipeline will interconnect with a 8" sour gas pipeline owned and operated by the applicant. The pipeline will be constructed and operated in accordance with rules and regulations adopted by the Railroad Commission of Texas specifying construction material and methods for the safe operation of sour gas pipelines.

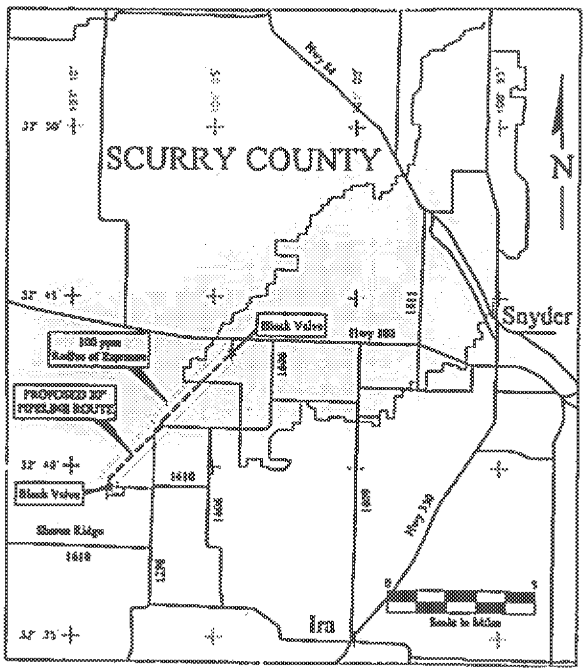
This proposed pipeline facility will transport sour gas that contains more than 100 ppm of hydrogen sulfide. A copy of this application is available for public inspection at the offices of the Leon County Clerk, located at the following address: the corner of Cass Street and St. Mary Street in Centerville, Texas.

Any owner or occupant of land located within 100 ppm radius of exposure of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to Gas Utilities Docket (GUD) No. 8899 and stating their desire to protest to:

Docket Services
Office of General Counsel
Railroad Commission of Texas
P. O. Box 12967
Austin, Texas 78711-2967

Protests must be received no later than September 19, 1998. It is recommended that a copy of this notice be included with the letter. Additional information concerning the protest procedure can be obtained by calling (512) 463-7017 or by visiting www.rrc.state.tx.us on the Internet. For more information regarding this permit application you may contact Rob Koenig, Koch Midstream Services Company, 606 S. Shelby Street, Carthage, Texas 75633, Telephone: (903) 693-5172 ext. 2542.





NOTICE OF APPLICATION FOR PIPELINE PERMIT

PennzEnergy Exploration & Production, L.L.C., 4632 W Hwy 180, Snyder, Texas 79549, has applied to the Railroad Commission of Texas for a permit to construct 7.5 miles of 20" buried pipeline in Scurry County, Texas to gather produced gas at the Sharon Ridge Canyon Unit, Tank Battery 5. The gas transported within the proposed gas gathering line will contain concentrations of Hydrogen Sulfide greater than 100 ppm. In the event of a leak, the radius of exposure of Hydrogen Sulfide for 100 ppm could extend 1,577 feet on either side of the pipeline based on methods outlined in 16 Texas Administration Code 3.36. The radius of exposure of Hydrogen Sulfide for 500 ppm could extend 720 feet on either side of the pipeline. The proposed sour gas pipeline will be located in Scurry County as shown on the plat. The pipeline will be constructed and operated in accordance with rules and regulations adopted by the Railroad Commission of Texas specifying construction material and methods for the safe operation of sour gas pipelines. A copy of the application is available at the office of the Scurry County Clerk, located at 1806 25th Street, Snyder, Texas 79549.

Any owner or occupant of land located within the 100 ppm radius of exposure of the proposed sour gas pipeline desiring to protest can do so by mailing or otherwise delivering a letter referring to Gas Utilities Docket Number 8937 and stating their desire to protest:

Docket Services
Office of General Counsel
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

Protests must be received no later than May 1, 1999. It is recommended that a copy of this notice be included with the letter.

(g) Protests. Affected persons have standing to file a protest to an application. In the event the final proposed pipeline route is not known at the time of application, any person who owns or occupies real property located within the area of influence identified in the application shall have standing to file a protest to an application. All such protests shall:

(1) be in writing and filed at the commission no later than the 30th day after the notice is published in a newspaper in the county in which the person filing the protest owns or occupies real property;

(2) state the name, address, and telephone number of every person on whose behalf the protest is being filed; and

As in effect on 12/20/2021.

(3) include a statement of the facts on which the person filing the protest relies to conclude that each person on whose behalf the protest is being filed is an affected person, as defined in subsection (a)(1) of this section.

(h) Division Review.

(1) Within 14 days of receipt of the application, the commission's designee will provide notice to the applicant that the application is either complete and accepted for filing, or incomplete and specify the additional information required for acceptance. Such notice shall be provided in writing by mail or by electronic mail if the applicant submits with the application a written request that communications regarding application completeness or deficiencies be communicated by electronic mail and provides an accurate electronic mail address. The application shall be completed within 30 days of notification that the application is incomplete or such longer time as may be requested by the applicant, in writing, and approved by the commission's designee. If the application is not completed within the specified time period, the commission's designee shall send notice of intent to deny the application to the applicant. Within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the applicant may request a hearing on the application as it exists at that time. If a request for hearing is not filed within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the application shall be dismissed without prejudice by the commission's designee.

(2) The commission's designee shall make a written recommendation as to whether the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility comply with the rules and safety standards of the commission if the application is not protested, by the latter of the 14th day after the end of the 30-day protest period or the 14th day after the day notice of a complete application is issued.

(3) If, pursuant to subsection (i) of this section, a hearing is held, the staff may introduce evidence relating to the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility.

(4) In determining whether or not the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility comply with the rules and safety standards of the commission, relevant provisions of §3.36 and §3.70 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, and Pipeline Permits Required, respectively) shall be considered. If applicable, Chapter 8 of this title (relating to Pipeline Safety Regulations) shall also be considered.

(5) If no affected person files a protest with the commission by the 30th day after the date notice of application was published, the commission's designee shall either make a written recommendation that the permit be issued, that the permit be granted subject to specific conditions required to ensure compliance with applicable laws and regulations, or that the permit be denied. If the commission's designee recommends that the permit be conditionally granted or be denied, the reasons for such recommendation shall be explained. If the commission's designee recommends that the application be conditionally granted or be denied, the applicant shall have a right to a hearing upon written request received no later than 15 days after the date of issuance of notice of conditional grant or denial.

(i) Hearing.

(1) A hearing shall be convened to consider an application for a sour gas pipeline construction permit if:

(A) a protest is timely filed by an affected person;

(B) a request is timely filed by the applicant; or

(C) the commission so elects on its own motion.

(2) The Office of General Counsel shall assign an examiner who shall conduct a hearing in accordance with the procedural requirements of Texas Government Code, Chapter 2001 (the Administrative Procedure Act), and Chapter 1 of this title (relating to the general rules of practice and procedure).

(3) The commission shall convene a hearing not later than the 60th day after a protest is filed, the applicant submits a request for hearing, or the commission gives notice of intent to convene a hearing on its own motion. If the application is not complete as of the date the request for hearing is filed or notice of hearing issued, the 60-day time period for convening a hearing shall not begin to run until such time as notice of a complete application is issued unless the hearing is held pursuant to the provisions of subsection (h)(1). If the hearing is held pursuant to the provisions of subsection (h)(1), the hearing will be held within 60 days of receipt of a request for hearing.

(4) In any hearing convened to consider an application, the applicant has the burden of showing that the materials to be used in and method of construction and operation comply with the applicable rules and safety standards adopted by the commission.

(j) Order.

(1) An order approving an application shall include a finding that the materials to be used in and method of construction and operation of the facility comply with the applicable rules and safety standards adopted by the commission. If an application meets all the requirements of §3.70 of this title, relating to Pipeline Permits Required, including the requirements of §3.36 of this title, relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, the order may approve the certificate of compliance (Form H-9) or grant the pipeline permit or both.

(2) An order denying an application shall state the

reason or reasons for the denial.

(3) In the case of an application for which a hearing is conducted, the commission will render a decision not later than the 60th day after the date on which the hearing is finally closed.

(4) If no hearing is held on an application, the commission will render a decision as soon as practicable but not later than the 60th day after the staff prepares its written recommendation in accordance with subsection (h)(2) and (4).

Source Note: The provisions of this §3.106 adopted to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.107 Penalty Guidelines for Oil and Gas Violations

(a) Policy. Improved safety and environmental protection are the desired outcomes of any enforcement action. Encouraging operators to take appropriate voluntary corrective and future protective actions once a violation has occurred is an effective component of the enforcement process. Deterrence of violations through penalty assessments is also a necessary and effective component of the enforcement process. A rule-based enforcement penalty guideline to evaluate and rank oil- and natural gas-related violations is consistent with the central goal of the Commission's enforcement efforts to promote compliance. Penalty guidelines set forth in this section will provide a framework for more uniform and equitable assessment of penalties throughout the state, while also enhancing the integrity of the Commission's enforcement program.

(b) Only guidelines. This section complies with the requirements of Texas Natural Resources Code, §81.0531 and §91.101, which provides the Commission with the authority to adopt rules, enforce rules, and issue permits relating to the prevention of pollution. The penalty amounts shown in the tables in this section are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of provisions of Texas Natural Resources Code, Title 3; Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; or the provisions of a rule adopted or order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29. This rule does not contemplate automatic enforcement. Violations can be corrected by operators before being referred to legal enforcement.

(c) Commission authority. The establishment of these penalty guidelines shall in no way limit the Commission's authority and discretion to cite violations and assess administrative penalties. The guideline minimum penalties listed in this section are for the most common violations cited; however, this is neither an exclusive nor an exhaustive list of violations that the Commission may cite. The Commission retains full authority and discretion to cite violations of Texas Natural Resources Code, Title 3; including Nat. Res. Code §91.101, which provides the Commission with the authority to adopt rules, enforce rules, and issue permits relating to the prevention of pollution; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section.

(d) Factors considered. The amount of any penalty requested, recommended, or finally assessed in an enforcement action will be determined on an individual case-by-case basis for each violation, taking into consideration the following factors:

(1) the person's history of previous violations;

(2) the seriousness of the violation;

(3) any hazard to the health or safety of the public; and

(4) the demonstrated good faith of the person charged.

(e) Typical penalties. Regardless of the method by which the guideline typical penalty amount is calculated, the total penalty amount will be within the statutory limit.

(1) A guideline of typical penalties for violations of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, are set forth in Table 1.

Table 1. Penalty Guideline

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.2	Commission denied access	$1,000
16 TAC §3.3	failure to comply with well sign requirements	$500
16 TAC §3.3	failure to comply with entrance sign requirements	$1,000
16 TAC §3.3	failure to comply with tank battery sign requirements	$1,000
16 TAC §3.5(a)	no drilling permit approved	$5,000
16 TAC §3.5(a)	no drilling permit: no application filed	$10,000

As in effect on 12/20/2021.

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.8(b)	pollution of surface or subsurface water	$1,000 minimum
16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: dry pit area	$500 base penalty plus $0.30/sq. ft.
16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: wet pit area	$500 base penalty plus $0.50/sq. ft.
16 TAC §3.8(d)(2)	use of prohibited pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.
16 TAC §3.8(d)(2)	use of prohibited pits: salt water or other fluid area	$2,500 base plus $0.75 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: salt water or other fluid pit area	$2,500 base plus $0.75 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: dry	$2,500
16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: wet	$5,000
16 TAC §3.9(1)	no permit to dispose or inject	$5,000
16 TAC §3.9(9)(A)	failure to comply with tubing and packer requirements	$2,000
16 TAC §3.9(9)(B)	no pressure observation valve	$1,000 per valve
16 TAC §3.9(12)	no test, failed test, or no Form H-5	$5,000
16 TAC §3.13(b)(1)(B)	open casing/tubing	$1,000 to $5,000
16 TAC §3.13(b)(1)(C)	failure to comply with wellhead control requirements	$5,000
16 TAC §3.13(b)(2)	failure to comply with surface casing requirements	$2,000
16 TAC §3.14(a)(2)	failure to file Form W-3A	$2,500
16 TAC §3.14(a)(3)	failure to notify of setting plugs	$1,500
16 TAC §3.14(b)(1)	failure to file Form W-3	$5,000
16 TAC §3.14(b)(2)	failure to plug onshore well	$2,000 plus $1/ft. of total depth
16 TAC §3.14(b)(2)	failure to plug bay, estuary, or inland waterway well	$15,000 plus $2 per foot of total depth, subject to statutory maximum
16 TAC §3.14(b)(2)	failure to plug offshore well	$50,000 plus $5 per foot of total depth, subject to statutory maximum
16 TAC §3.14(d)(1)-(11)	failure to follow general plugging requirement	$1,000
16 TAC §3.14(d)(12)	failure to remove miscellaneous loose junk and trash	$1,000
16 TAC §3.14(d)(12)	failure to remove tanks, vessels, and related piping	$2,500
16 TAC §3.14(d)(12)	failure to empty tanks, vessels, and related piping	$5,000
16 TAC §3.15(l)(7)	failure to test prior to reactivating well	$1,000
16 TAC §3.15(f)(2)(A)	failure to disconnect electricity	$5,000
16 TAC §3.15(f)(2)(A)	failure to purge vessels	$7,500
16 TAC §3.15(f)(2)(A)	failure to remove equipment	$10,000
16 TAC §3.16(b) and (c)	failure to file completion records/logs	$2,500
16 TAC §3.17	Bradenhead violations: no valve; no access; or pressure on it	$1,000 to $2,500
16 TAC §3.20(a)(1)	failure to notify of incident	$2,500 to $5,000
16 TAC §3.21(a)-(i)	improper fire prevention	$1,000
16 TAC §3.21(j)	failure to comply with dike/firewall requirements	$2,500
16 TAC §3.21(k)	swabbing without authority	$1,000 per well
16 TAC §3.21(l)	failure to comply with electric power line requirements	$2,000
16 TAC §3.22	no nets	compliance
16 TAC §3.35(a)	failure to notify of lost logging tool	$5,000
16 TAC §3.35(b)	failure to properly abandon lost logging tool	$5,000
16 TAC §3.36(c)(5)(B)	improper storage tank signs in a non-public area	$1,000
16 TAC §3.36(c)(5)(B)	improper storage tank signs in a public area	$2,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a non-public area	$1,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a public area	$2,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a populated public area	$5,000
16 TAC §3.36(c)(6)(B)	failure to fence specific area at a well	$5,000
16 TAC §3.36(c)(6)(B)	failure to fence specific area at a battery	$10,000
16 TAC §3.36(c)(6)(C)	materials provision	$2,500
16 TAC §3.36(c)(8)	failure to maintain H_2S equipment	$5,000
16 TAC §3.36(c)(9)(Q)	failure to update contingency plan	$2,500
16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	more than 6 hours up to 12 hours-$5,000
16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	12 hours or more-$10,000
16 TAC §3.36(c)(14)	failure to notify of H_2S release	more than 6 hours up to 12 hours-$5,000
16 TAC §3.36(c)(14)	failure to notify of H_2S release	12 hours or more-$10,000

As in effect on 12/20/2021.

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; no injury	$5,000
16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; injury or death	$10,000
16 TAC §3.36(c)(12)(F)	failure to notify of drill stem test in H_2S formation	$2,000
16 TAC §3.36(c)(13)	failure to have H_2S trained personnel	$5,000 per person
16 TAC §3.36(d)(1)(E)	failure to file Form H-9; non-public area	$1,000
16 TAC §3.36(d)(1)(E)	failure to file Form H-9; public area	$10,000
16 TAC §3.36(d)(2)	failure to identify well as sour on completion report	$10,000
16 TAC §3.36(d)(3)	intentional failure to file written report of H_2S release	$3,000
16 TAC §3.36(d)(3)	failure to file written report of emergency H_2S release	$5,000
16 TAC §3.46(a)	no permit to dispose or inject	$5,000
16 TAC §3.46(g)(1)	failure to comply with tubing and packer requirements	$2,000
16 TAC §3.46(g)(2)	no pressure observation valve	$1,000 per valve
16 TAC §3.46(j)	no test, failed test, or no Form H-5	$5,000
16 TAC §3.57	reclamation plant operation violation	$1,000
16 TAC §3.65(c), (d), or (f)	failure to file Form CI-D or Form CI-X	$1,000
16 TAC §3.65(g)	failure to provide critical customer information	$2,500
16 TAC §3.73(a)	failure to notify of pipeline connection	$1,000
16 TAC §3.73(h)	reconnecting, transporting from well/lease without approved Form P-4	$1,000 minimum; see Table 1A for additional amount
16 TAC §3.73(j)	reporting, producing, injecting, disposing without approved Form P-4	$1,000 minimum; see Table 1A for additional amount
16 TAC §3.81	failure to comply with brine mining injection well operation requirements	$1,000
16 TAC §3.95	failure to comply with underground salt formation liquid or liquefied hydrocarbon storage facility operation requirements	$2,000
16 TAC §3.96	failure to comply with underground productive or depleted reservoir gas storage facility operation requirements	$2,000
16 TAC §3.97	failure to comply with underground salt formation gas storage facility operation requirements	$2,000
16 TAC §3.98	failure to comply with hazardous waste disposal operation requirements	$2,000
16 TAC §3.99(d)(2)	failure to comply with protection/isolation of usable quality water requirements	$2,500 per well
16 TAC §3.99(e)	failure to comply with cathodic protection well construction requirements	$1,000 per well
16 TAC §3.99(g)	failure to file completion report	$1,000 per well
16 TAC §3.100(d)(2)	failure to permit seismic/core holes penetrating usable quality water	$1,000 per hole
16 TAC §3.100(f)	failure to properly plug seismic/core holes	$1,000 per hole
16 TAC §3.100(g)	failure to file final survey report	$5,000 per survey
16 TAC §3.106(b)	commenced construction of a sour gas pipeline facility without a permit	$10,000
16 TAC §3.106(e)	published notice with egregious errors/omissions	$5,000
16 TAC §3.106(f)	provided pipeline plat with egregious errors/omissions	$5,000
Tex. Nat. Res. Code, §91.143	false filing	$1,000 per form

(2) Guideline penalties for violations of §3.73 of this title, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance, include additional penalty amounts that are based on four components. In combination, these four components yield the factor by which an additional penalty amount of $1,000 is multiplied. The various combinations of the components are set forth in Table 1A.

(A) The first component is the length of the violation. A low rating means the violation has been in existence less than three months. A medium rating means the violation has been outstanding for more than three months and up to one year. A high rating means the violation has been outstanding for more than one year.

(B) The second component is production value. A low rating means the value of the production is less than $5,000. A medium rating means the value of the production is more than $5,000 and up to $100,000. A high rating means the value of the production is more than $100,000.

(C) The third component is the number of unresolved severances. A low rating means there are fewer than two unresolved severances. A medium rating means there are more than two and up to six unresolved severances. A high rating means there are more than six unresolved severances.

(D) The fourth component is the basis of the severance. The letter "N" indicates that the severance is not pollution related. The letter "Y" indicates that the severance is pollution related.

Table 1A. Calculation of Additional Guideline Penalty Amounts for Violations of 16 Tex. Admin. Code §3.73, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance

Length of Violation Low: < 3 mos. Medium: High: > 1 yr.	Production Value Low: < $5,000 Medium: High: > $100,000	Unresolved Severances Low: < 2 Medium: High: > 6	Basis of Severance N: non-pollution related Y: pollution related	Factor
low	low	low	N	1.0
low	low	medium	N	1.5
low	low	high	N	1.5
low	medium	low	N	1.5
low	medium	medium	N	3.5
low	medium	high	N	5.0
low	high	low	N	4.5
low	high	medium	N	7.0
low	high	high	N	7.5
medium	low	low	N	1.5
medium	low	medium	N	2.5
medium	low	high	N	3.5
medium	medium	low	N	3.5
medium	medium	medium	N	5.0
medium	medium	high	N	8.0
medium	high	low	N	8.5
medium	high	medium	N	9.0
medium	high	high	N	10.0
high	low	low	N	2.5
high	low	medium	N	3.5
high	low	high	N	3.5
high	medium	low	N	4.5
high	medium	medium	N	7.5
high	medium	high	N	8.0
high	high	low	N	10.0
high	high	medium	N	10.0
high	high	high	N	10.0
low	low	low	Y	1.5
low	low	medium	Y	2.0
low	low	high	Y	2.5
low	medium	low	Y	3.0
low	medium	medium	Y	5.0
low	medium	high	Y	7.5
low	high	low	Y	5.0
low	high	medium	Y	8.0
low	high	high	Y	8.5
medium	low	low	Y	2.0
medium	low	medium	Y	3.5
medium	low	high	Y	7.0
medium	medium	low	Y	7.0
medium	medium	medium	Y	7.5
medium	medium	high	Y	8.5
medium	high	low	Y	9.0
medium	high	medium	Y	9.5
medium	high	high	Y	10.0
high	low	low	Y	3.0
high	low	medium	Y	4.0

As in effect on 12/20/2021.

Length of Violation Low: < 3 mos. Medium: High: > 1 yr.	Production Value Low: < $5,000 Medium: High: > $100,000	Unresolved Severances Low: < 2 Medium: High: > 6	Basis of Severance N: non-pollution related Y: pollution related	Factor
high	low	high	Y	5.0
high	medium	low	Y	5.0
high	medium	medium	Y	8.5
high	medium	high	Y	9.0
high	high	low	Y	10.0
high	high	medium	Y	10.0
high	high	high	Y	10.0

(f) Penalty enhancements for certain violations. For violations that involve threatened or actual pollution; result in threatened or actual safety hazards; or result from the reckless or intentional conduct of the person charged, the Commission may assess an enhancement of the guideline penalty amount. The enhancement may be in any amount in the range shown for each type of violation as shown in Table 2.

Table 2. Penalty Enhancements

Evidentiary Factors	Threatened or Actual Pollution	Safety Hazard	Severity of Violation
Agricultural land or sensitive wildlife habitat	$1,000 to $5,000		
Endangered or threatened species	$2,000 to $10,000		
Bay, estuary or marine habitat	$5,000 to $25,000		
Minor freshwater source (minor aquifer, seasonal watercourse)	$2,500 to $7,500		
Major freshwater source (major aquifer, creeks, rivers, lakes and reservoirs)	$5,000 to $25,000		
Impacted residential/public areas		$1,000 to $15,000	
Hazardous material release		$2,000 to $25,000	
Reportable incident/accident		$5,000 to $25,000	
Well in H_2S field		up to $10,000	
Time out of compliance			$100 to $2,000 / month
Reckless conduct of operator			double total penalty
Intentional conduct of operator			triple total penalty

(g) Penalty enhancements for certain violators. For violations in which the person charged has a history of prior violations within seven years of the current enforcement action, the Commission may assess an enhancement based on either the number of prior violations or the total amount of previous administrative penalties, but not both. The actual amount of any penalty enhancement will be determined on an individual case-by-case basis for each violation. The guidelines in Tables 3 and 4 are intended to be used separately. Either guideline may be used where applicable, but not both.

Table 3. Penalty enhancements based on number of prior violations within seven years

Number of violations in the seven years prior to action	Enhancement amount
One	$1,000
Two	$2,000
Three	$3,000
Four	$4,000
Five or more	$5,000

Table 4. Penalty Enhancements based on total amount of prior penalties within seven years

Total administrative penalties assessed in the seven years prior to	Enhancement amount

As in effect on 12/20/2021.

action	
Less than $10,000	$1,000
Between $10,000 and $25,000	$2,500
Between $25,000 and $50,000	$5,000
Between $50,000 and $100,000	$10,000
Over $100,000	10% of total amount

(h) Penalty reduction for accelerated settlement before hearing. The recommended monetary penalty for a violation may be reduced by up to 50% if the person charged agrees to an accelerated settlement before the Commission conducts an administrative hearing to prosecute a violation. Once the hearing is convened, the opportunity for the person charged to reduce the basic monetary penalty is no longer available. The reduction applies to the basic penalty amount requested and not to any requested enhancements.

(i) Demonstrated good faith. In determining the total amount of any monetary penalty requested, recommended, or finally assessed in an enforcement action, the Commission may consider, on an individual case-by-case basis for each violation, the demonstrated good faith of the person charged. Demonstrated good faith includes, but is not limited to, actions taken by the person charged before the filing of an enforcement action to remedy, in whole or in part, a violation or to mitigate the consequences of a violation.

As in effect on 12/20/2021.

(j) Penalty calculation worksheet. The penalty calculation worksheet shown in Table 5 lists the guideline minimum penalty amounts for certain violations; the circumstances justifying enhancements of a penalty and the amount of the enhancement; and the circumstances justifying a reduction in a penalty and the amount of the reduction.

Table 5. Penalty Calculation Worksheet

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
1	16 TAC §3.2	Commission denied access	$1,000	$
2	16 TAC §3.3	failure to comply with well sign requirements	$500	$
3	16 TAC §3.3	failure to comply with entrance sign requirements	$1,000	$
4	16 TAC §3.3	failure to comply with tank battery sign requirements	$1,000	$
5	16 TAC §3.5(a)	no drilling permit: filed but not approved	$5,000	$
6	16 TAC §3.5(a)	no drilling permit: no application filed	$10,000	$
7	16 TAC §3.8(b)	pollution of surface or subsurface water	$1,000 minimum	$
8	16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: dry pit area	$500 base penalty plus $0.30/sq. ft.	$
9	16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: wet pit area	$500 base penalty plus $0.50/sq. ft.	$
10	16 TAC §3.8(d)(2)	use of prohibited pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.	$
11	16 TAC §3.8(d)(2)	use of prohibited pits: salt water or other fluid area	$2,500 base plus $0.75 sq. ft.	$
12	16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.	$
13	16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: salt water or other fluid pit area	$2,500 base plus $0.75 sq. ft.	$
14	16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: dry	$2,500	$
15	16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: wet	$5,000	$
16	16 TAC §3.9(1)	no permit to dispose or inject	$5,000	$
17	16 TAC §3.9(9)(A)	failure to comply with tubing and packer requirements	$2,000	$
18	16 TAC §3.9(9)(B)	no pressure observation valve	$1,000 per valve	$
19	16 TAC §3.9(12)	no test, failed test, or no Form H-5	$5,000	$
20	16 TAC §3.13(b)(1)(B)	open casing/tubing	$1,000 to $5,000	$
21	16 TAC §3.13(b)(1)(C)	failure to comply with wellhead control requirements	$5,000	$
22	16 TAC §3.13(b)(2)	failure to comply with surface casing requirements	$2,000	$
23	16 TAC §3.14(a)(2)	failure to file Form W-3A	$2,500	$
24	16 TAC §3.14(a)(3)	failure to notify of setting plugs	$1,500	$
25	16 TAC §3.14(b)(1)	failure to file Form W-3	$5,000	$
26	16 TAC §3.14(b)(2)	failure to plug onshore well	$2,000 plus $1/ft. of total depth	$
27	16 TAC §3.14(b)(2)	failure to plug bay, estuary, or inland waterway well	$15,000 plus $2 per foot of total	$

As in effect on 12/20/2021.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
			depth, subject to statutory maximum	
28	16 TAC §3.14(b)(2)	failure to plug offshore well	$50,000 plus $5 per foot of total depth, subject to statutory maximum	$
29	16 TAC §3.14(d)(1)-(11)	failure to follow general plugging requirement	$1,000	$
30	16 TAC §3.14(d)(12)	failure to remove miscellaneous loose junk and trash	$1,000	$
31	16 TAC §3.14(d)(12)	failure to remove tanks, vessels, and related piping	$2,500	$
32	16 TAC §3.14(d)(12)	failure to empty tanks, vessels, and related piping	$5,000	$
33	16 TAC §3.15(l)(7)	failure to test prior to reactivating well	$1,000	$
34	16 TAC §3.15(f)(2)(A)	failure to disconnect electricity	$5,000	$
35	16 TAC §3.15(f)(2)(A)	failure to purge vessels	$7,500	$
36	16 TAC §3.15(f)(2)(A)	failure to remove equipment	$10,000	$
37	16 TAC §3.16(b) and (c)	failure to file completion records/logs	$2,500	$
38	16 TAC §3.17	Bradenhead violations: no valve; no access; or pressure on it	$1,000 to $2,500	$
39	16 TAC §3.20(a)(1)	failure to notify of incident	$2,500 to $5,000	$
40	16 TAC §3.21(a)-(i)	improper fire prevention	$1,000	$
41	16 TAC §3.21(j)	failure to comply with dike/firewall requirements	$2,500	$
42	16 TAC §3.21(k)	swabbing without authority	$1,000 per well	$
43	16 TAC §3.21(l)	failure to comply with electric power line requirements	$2,000	$
44	16 TAC §3.22	no nets	compliance	
45	16 TAC §3.35(a)	failure to notify of lost logging tool	$5,000	$
46	16 TAC §3.35(b)	failure to properly abandon lost logging tool	$5,000	$
47	16 TAC §3.36(c)(5)(B)	improper storage tank signs in a non-public area	$1,000	$
48	16 TAC §3.36(c)(5)(B)	improper storage tank signs in a public area	$2,000	$
49	16 TAC §3.36(c)(6)(A)	improper entry signs in a non-public area	$1,000	$
50	16 TAC §3.36(c)(6)(A)	improper entry signs in a public area	$2,000	$
51	16 TAC §3.36(c)(6)(A)	improper entry signs in a populated public area	$5,000	$
52	16 TAC §3.36(c)(6)(B)	failure to fence specific area at a well	$5,000	$
53	16 TAC §3.36(c)(6)(B)	failure to fence specific area at a battery	$10,000	$
54	16 TAC §3.36(c)(6)(C)	materials provision	$2,500	$
55	16 TAC §3.36(c)(8)	failure to maintain H_2S equipment	$5,000	$
56	16 TAC §3.36(c)(9)(Q)	failure to update contingency plan	$2,500	$
57	16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	more than 6 hours up to 12 hours-$5,000	$

As in effect on 12/20/2021.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
58	16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	12 hours or more-$10,000	$
59	16 TAC §3.36(c)(14)	failure to notify of H_2S release	more than 6 hours up to 12 hours-$5,000	$
60	16 TAC §3.36(c)(14)	failure to notify of H_2S release	12 hours or more-$10,000	$
61	16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; no injury	$5,000	$
62	16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; injury or death	$10,000	$
63	16 TAC §3.36(c)(12)(F)	failure to notify of drill stem test in H_2S formation	$2,000	$
64	16 TAC §3.36(c)(13)	failure to have H_2S trained personnel	$5,000 per person	$
65	16 TAC §3.36(d)(1)(E)	failure to file Form H-9; non-public area	$1,000	$
66	16 TAC §3.36(d)(1)(E)	failure to file Form H-9; public area	$10,000	$
67	16 TAC §3.36(d)(2)	failure to identify well as sour on completion report	$10,000	$
68	16 TAC §3.36(d)(3)	intentional failure to file written report of H_2S release	$3,000	$
69	16 TAC §3.36(d)(3)	failure to file written report of emergency H_2S release	$5,000	$
70	16 TAC §3.46(a)	no permit to dispose or inject	$5,000	$
71	16 TAC §3.46(g)(1)	failure to comply with tubing and packer requirements	$2,000	$
72	16 TAC §3.46(g)(2)	no pressure observation valve	$1,000 per valve	$
73	16 TAC §3.46(j)	no test, failed test, or no Form H-5	$5,000	$
74	16 TAC §3.57	reclamation plant operation violation	$1,000	$
75	16 TAC §3.65(c), (d), or (f)	failure to file Form CI-D or Form CI-X	$1,000	$
76	16 TAC §3.65(g)	failure to provide critical customer information	$2,500	$
77	16 TAC §3.73(a)	failure to notify of pipeline connection	$1,000	$
78	16 TAC §3.73(h)	reconnecting, transporting from well/lease without approved Form P-4	$1,000 minimum; see Table 1A for additional amount	$
79	16 TAC §3.73(j)	reporting, producing, injecting, disposing without approved Form P-4	$1,000 minimum; see Table 1A for additional amount	$
80	16 TAC §3.81	failure to comply with brine mining injection well operation requirements	$1,000	$
81	16 TAC §3.95	failure to comply with underground salt formation liquid or liquefied hydrocarbon storage facility operation requirements	$2,000	$
82	16 TAC §3.96	failure to comply with underground productive or depleted reservoir gas storage facility operation requirements	$2,000	$
83	16 TAC §3.97	failure to comply with underground salt formation gas storage facility operation requirements	$2,000	$
84	16 TAC §3.98	failure to comply with hazardous waste disposal operation requirements	$2,000	$
85	16 TAC §3.99(d)(2)	failure to comply with protection/isolation of usable quality water requirements	$2,500 per well	$
86	16 TAC §3.99(e)	failure to comply with cathodic protection well construction requirements	$1,000 per well	$
87	16 TAC §3.99(g)	failure to file completion report	$1,000 per well	$

As in effect on 12/20/2021.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
88	16 TAC §3.100(d)(2)	failure to permit seismic/core holes penetrating usable quality water	$1,000 per hole	$
89	16 TAC §3.100(f)	failure to properly plug seismic/core holes	$1,000 per hole	$
90	16 TAC §3.100(g)	failure to file final survey report	$5,000 per survey	$
91	16 TAC §3.106(b)	commenced construction of a sour gas pipeline facility without a permit	$10,000	$
92	16 TAC §3.106(e)	published notice with egregious errors/omissions	$5,000	$
93	16 TAC §3.106(f)	provided pipeline plat with egregious errors/omissions	$5,000	$
94	Tex. Nat. Res. Code, §91.143	false filing	$1,000 per form	$
95	**Subtotal of guideline penalty amounts from Table 1 (lines 1-94, inclusive)**			$
96	**Reduction for settlement before hearing: up to 50% of line 95 amt.**		%	$
97	**Subtotal: amount shown on line 95 less applicable settlement reduction on line 96**			$
	Penalty enhancement amounts for threatened or actual pollution from Table 2			
98	Agricultural land or sensitive wildlife habitat		$1,000 to $5,000	$
99	Endangered or threatened species		$2,000 to $10,000	$
100	Bay, estuary or marine habitat		$5,000 to $25,000	$
101	Minor freshwater source (minor aquifer, seasonal watercourse)		$2,500 to $7,500	$
102	Major freshwater source (major aquifer, creeks, rivers, lakes and reservoirs)		$5,000 to $25,000	$
	Penalty enhancement amounts for safety hazard from Table 2			
103	Impacted residential/public areas		$1,000 to $15,000	$
104	Hazardous material release		$2,000 to $25,000	$
105	Reportable incident/accident		$5,000 to $25,000	$
106	Well in H_2S field		up to $10,000	$
	Penalty enhancement amounts for severity of violation from Table 2			
107	Time out of compliance		$100 to $2,000 each month	$
108	**Subtotal: amount shown on line 97 plus all amounts on lines 98 through 107, inclusive**			$
	Penalty enhancements for culpability of person charged from Table 2			
109	Reckless conduct of operator		double line 108 amount	$
110	Intentional conduct of operator		triple line 108 amount	$
	Penalty enhancements for number of prior violations within past seven years from Table 3			
111	One		$1,000	$
112	Two		$2,000	$
113	Three		$3,000	$
114	Four			

As in effect on 12/20/2021.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
			$4,000	$
115	Five or more		$5,000	$
	Penalty enhancements for amount of penalties within past seven years from Table 4			
116	Less than $10,000		$1,000	$
117	Between $10,000 and $25,000		$2,500	$
118	Between $25, 000 and $50,000		$5,000	$
119	Between $50,000 and $100,00		$10,000	$
120	Over $100,000		10% of total amt.	$
121	**Subtotal: Line 97 amt. plus amts. on line 109 and/or 110 plus the amt. shown on any line from 111 through 120, inclusive**			$
122	**Reduction for demonstrated good faith of person charged**			$
123	**TOTAL PENALTY AMOUNT: amount on line 121 less any amount shown on line 122**			$

Source Note: The provisions of this §3.107 adopted to be effective August 27, 2012, 37 TexReg 6540; amended to be effective December 20, 2021, 46 TexReg 8688.